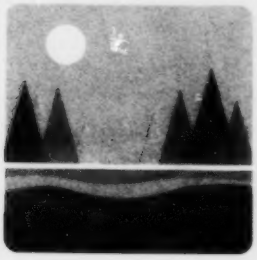
CANADIAN
PETROLEUM
ASSOCIATION

# $CO_2$ REDUCTION THROUGH ENERGY CONSERVATION

Prepared by
RTM Engineering
May 1991



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## TABLE OF CONTENTS

| | | Page |
|---|---|---|
| Title Page | | i |
| Table of Contents | | ii |
| List of Tables | | v |
| Abbreviations | | vi |
| Acknowledgements | | vii |
| Overview of Oil and Gas Industry $CO_2$ Reduction Potential Through Energy Conservation | | ix |
| **1.0** | **SUMMARY** | 1 |
| 1.1 | Introduction | 1 |
| 1.2 | Economic $CO_2$ Reduction | 1 |
| 1.3 | Challenges and Opportunities | 3 |
| 1.4 | Recommendations | 3 |
| 1.4.1 | Conclusions | 3 |
| 1.4.2 | Recommendations | 4 |
| **2.0** | **INTRODUCTION** | 6 |
| 2.1 | General | 6 |
| 2.2 | Economic Criteria | 7 |
| **3.0** | **BACKGROUND** | 8 |
| 3.1 | Preamble | 8 |
| 3.2 | $CO_2$ Emission Levels | 9 |
| 3.2.1 | Current Emissions | 9 |
| 3.2.2 | Projected Emissions Without Energy Conservation | 9 |
| 3.2.3 | Alberta Department of Energy Estimates | 10 |
| 3.2.4 | $CO_2$ Recovery and Disposal Potential | 11 |
| 3.2.5 | $CO_2$ in Sales Gas | 11 |
| 3.3 | $CO_2$ Emission Factors | 11 |
| **4.0** | **ECONOMIC ENERGY CONSERVATION POTENTIAL** | 13 |
| 4.1 | Preamble | 13 |
| 4.2 | Economic Energy Conservation Measures | 13 |

## TABLE OF CONTENTS

| | | Page |
|---|---|---|
| 4.3 | Supplementary Lists | 15 |
| 4.4 | Site Energy Awareness Programs | 16 |
| 4.5 | Cogeneration at Gas Plants | 17 |
| 4.5.1 | General | 17 |
| 4.5.2 | Gas Plants With High Sulphur Recovery | 18 |
| 4.5.3 | Gas Plants With Low Sulphur Recovery | 18 |
| 4.5.4 | Sensitivities | 20 |
| 4.5.5 | Potential for Cogeneration | 22 |
| 4.6 | Flaring | 24 |
| 4.6.1 | Plant Flaring | 24 |
| 4.6.2 | Field Flaring | 25 |
| 4.6.3 | Electricity From Flared Associated Gas | 25 |
| 4.7 | Economic Energy Conservation Potential | 27 |
| **5.0** | **CHALLENGES TO ENERGY CONSERVATION** | **29** |
| 5.1 | Introduction | 29 |
| 5.2 | Fuel Gas Value | 29 |
| 5.3 | Electricity Cost and Ease of Use | 30 |
| 5.4 | Utility Industry Economics and Policies | 30 |
| 5.4.1 | Cogeneration and Flare Gas Use | 30 |
| 5.4.2 | Wheeling | 31 |
| 5.4.3 | Demand Side Management Programs | 32 |
| 5.5 | Oil and Gas Industry Economics | 32 |
| 5.6 | Oil and Gas Industry Cycles | 33 |
| 5.7 | Government Regulations | 33 |
| 5.8 | Awareness of Energy Conservation Potential | 34 |
| 5.8.1 | Corporate Organization | 34 |
| 5.8.2 | Awareness | 35 |

## TABLE OF CONTENTS

| | | Page |
|---|---|---|
| **6.0** | **REPORTING** | **36** |
| 6.1 | Objectives | 36 |
| 6.2 | Canadian Industry Program for Energy Conservation (CIPEC) Example | 36 |
| 6.3 | Requirements | 37 |
| 6.3.1 | Reporting Mechanism | 37 |
| 6.3.2 | Sectorial Breakdowns | 38 |
| 6.3.3 | Energy Consumption Variables | 38 |
| 6.3.4 | $CO_2$ Production Data | 39 |
| 6.3.5 | $CO_2$ Emission Calculations | 39 |
| 6.3.6 | Provincial Summaries | 39 |
| 6.3.7 | Summary Reporting | 40 |
| 6.4 | Implementation | 40 |
| 6.4.1 | Industry/Government Task Team | 40 |
| 6.4.2 | Define Existing Reports | 41 |
| 6.4.3 | Additional Input | 41 |
| 6.4.4 | Data Analysis | 41 |
| 6.4.5 | Upstream Reporting Effort | 42 |
| 6.5 | Reporting Factors | 42 |
| 6.5.1 | Trends | 42 |
| 6.5.2 | Other Greenhouse Gases | 43 |
| 6.5.3 | 1990 Baseline and Forecasts | 43 |
| **7.0** | **CONCLUSIONS AND RECOMMENDATIONS** | **45** |
| 7.1 | Research and Development | 45 |

**APPENDICES**

A. $CO_2$ Emission Data
B. Short List Option Data
C. Supplementary List

## LIST OF TABLES


| Table No. | Description | Page |
|---|---|---|
| 3.2.3-1 | Comparison of Economic Bases and Alberta Department of Energy Studies | 10 |
| 4.2-1 | Economic Thermal Energy Measures | 14 |
| 4.2-2 | Economic Electrical Energy Measures | 15 |
| 4.5.5-1 | Example of Cogeneration Energy Savings | 23 |
| 4.6.3-1 | Example of Flare Gas Conservation by Electricity Generation | 27 |
| 4.7-1 | Economic Energy Conservation and $CO_2$ Reduction | 28 |

## ABBREVIATIONS

| | |
|---|---|
| AOSTRA | Alberta Oil Sands Technology and Research Authority |
| CCA | Capital Cost Allowance |
| CIPEC | Canadian Industrial Program for Energy Conservation |
| CPA | Canadian Petroleum Association |
| $CO_2$ | Carbon Dioxide |
| Cogeneration | Coproduction of electricity and heat energy (usually as steam) |
| DEA | Diethanolamine |
| ERCB | Energy Resources Conservation Board |
| EOR | Enhanced Oil Recovery |
| GCA | Gas Cost Allowance |
| GJ | Gigajoule ($10^9$ joules = 948 $10^3$ BTU's) |
| $H_2S$ | Hydrogen Sulphide |
| hp | Horse Power |
| IPAC | Independent Petroleum Association of Canada |
| KJ | Kilojoule ($10^3$) |
| kPa | Kilopascal Absolute |
| kt | Kilotonne |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| MDEA | Methyldiethanolamine |
| MEA | Monoethanolamine |
| MJ | Megajoule ($10^6$) |
| $NO_x$ | Nitrogen Oxides |
| PF | Power Factor |
| PJ | Petajoule ($10^{15}$) |
| PV | Present Value |
| $SO_2$ | Sulphur Dioxide |
| VOC | Volatile Organic Compounds |

## ACKNOWLEDGEMENTS

ACE Parker Mines & Minerals Corporation Limited
AECO (Conamara Limited)
Air Exchangers of Tulsa Oklahoma
Alberta Coal Research Authority
Alberta Energy
Alberta Environment
Amoco Canada Petroleum Company Limited
AOSTRA
Automax Controls Incorporated
Bennett & Emmott (1986) Limited
CanTech Corp
Catapillar
Cessco Fabrication and Engineering Limited
Cherco Compressors Limited
Clark (Dresser-Clark)
Cooper Energy Industries (Canada) Inc. Energy Services Group
CRI Catalyst Recovery Canada
Criterion Catalysts
Delavel Compressors
Dominion Oilfields Supply
Enerflex Systems Limited
Energy Industries Limited
Energy, Mines and Resources
Energy Resources Conservation Board
Energy Transfer Systems Limited
Environment Canada
Esso Resources Canada Limited
Exchange Industries
Flexpac International Corporation
Gulf Canada Resources Limited
Imperial Oil Commercial Department
IPPL
Katalco

## ACKNOWLEDGEMENTS

Natco Canada
Northwestern Utilities Limited
Nova Corporation of Alberta
Pamco Division of Enerflex Systems Limited
Petro Equipment Sales Limited
Petro-Canada
Province of British Columbia, Ministry of Energy, Mines and Petroleum Resources
Province of Manitoba Energy and Mines
Province of Saskatchewan Energy and Mines
Raychem Canada Limited
Read Turbo Expanders
Robbins and Myers
Shaw Pipe Protection Limited
Shell Canada Limited
Simark Controls Limited
Temco-Eclipse Limited
Trans Chemicals Incorporated
TransAlta Utilities Corporation
UMA Spantec Limited
Union Carbide Canada Limited
Union Pump (Canada) Limited
Wesco Division of Westinghouse Canada Inc.
Western Fuel Savers
Wilson Equipment

# OVERVIEW OF OIL AND GAS INDUSTRY $CO_2$ REDUCTION POTENTIAL THROUGH ENERGY CONSERVATION

Reduction of $CO_2$ emissions by means of increased energy efficiency is one policy option relative to global warming concerns. Economically attractive energy conservation measures can reduce oil and gas industry, exclusive of Athabasca oil sands operations, related $CO_2$ emissions by 6 to 7 percent. The energy conservation options identified in this study range from field energy awareness committees through to equipment retrofits and replacement.

At approximately 3 million tonnes a year, these reductions will not offset the increases in oil and gas $CO_2$ related emissions anticipated by producers and Alberta government agencies. There will be increasing emphasis on in-situ bitumen production, more energy intensive light crude oil production and increasing natural gas sales all continuing to increase energy inputs in excess of the reductions.

Unfortunately at this time, cogeneration of electricity for utility company distribution and for internally required steam at gas plants and at major in-situ production sites is not economic due in part to the low price paid for the electricity. Consideration is now being given to the use of gas now flared in oil fields for electricity generation. This opportunity may result in small reductions in $CO_2$ emissions at central electricity generating plants.

The report recommends much greater activity by industry relative to energy conservation awareness with emphasis on action and dialogue between various stakeholders to create more attractive conditions for energy conservation and the resultant $CO_2$ reduction.

# 1.0 SUMMARY

## 1.1 INTRODUCTION

As part of its ongoing program of promoting the environmental and economic efficiency of Canada's oil and gas industry, the Canadian Petroleum Association commissioned an analysis of the potential to economically reduce carbon dioxide, $CO_2$, emissions through energy conservation. As the principal greenhouse gas, $CO_2$ has become the subject of much scrutiny by industry, by governments and the public.

Due to oil and gas production operations and coal based electricity, Alberta and Saskatchewan per capita $CO_2$ emissions are above the national average, without consideration for credits due to use of much of the produced oil and gas outside the region. Alberta government agencies have forecast $CO_2$ emissions increases of over 34 percent by 2005. They also expect over 60 percent from increased in-situ bitumen production. Conversely these agencies indicate that the industry's ultimate reduction potential in $CO_2$ emissions may be even greater than the projected increase; however, achievement of this reduction would require many measures not economical in today's business climate.

Oil and gas industry related $CO_2$ emissions are largely due to combustion of gas as fuel in the industry and from associated emission due to electricity use. A small but growing amount is due to $CO_2$ contained in raw gas. This study of economic potential of energy conservation has concentrated on the combustion based $CO_2$.

## 1.2 ECONOMIC $CO_2$ REDUCTION

This study concludes that between 6 and 7 percent of current oil and gas related $CO_2$ emissions can be eliminated by measures currently available and economically attractive oil and gas companies. The capital cost for these measures is estimated at 54 million in 1991 dollars. The estimated reduction of $CO_2$ and capital cost needs do not include unique or infrequent site specific answers. This estimate of savings contrasts dramatically with the theoretical potential $CO_2$ reduction of 31 percent for

the oil and gas industry estimated in the Alberta Department of Energy's 1990 studies but the latter included all initiatives with payouts up to 10 years before tax. Here current industry average rates of return and tax factors were used in selecting the applicable options.

Relative to western Canada's oil and gas industry's current total $CO_2$ emissions of approximately 46 megatonnes a year, this study estimates the following reduction potential of 3.0 megatonnes or 6.5 percent:

- Identified measures with favourable economics - 2.1 megatonnes (4.5%)
- Local energy awareness programs - 0.5 megatonnes (1.1%)
- Flared gas use for electricity and NOVA pipeline efficiency program - 0.4 megatonnes (0.9%)

The identified measures can be grouped into thermal - fuel gas related - projects with predicted reductions of 1.4 megatonnes, largely in sour gas processing and electricity use reduction projects spread over most oil and gas industry sectors.

The local energy awareness programs will involve many zero and low cost approaches to reducing fuel gas and electricity use. Consideration of oil field flare gas use for electricity is now quite active but demonstration facilities and possibly revised regulations are needed for expanded use. NOVA already has a compressor drive efficiency improvement program in place involving the change-out of older gas turbines to more energy efficient units over a 10 year period.

Cogeneration of electricity for sale and heat for gas processing and in-situ bitumen production requires electricity purchase prices from utilities above those now available before becoming economic. If/when economics permit, cogeneration at oil and gas facilities could provide a major reduction in $CO_2$ now emitted from central coal based power stations.

## 1.3 CHALLENGES AND OPPORTUNITIES

The low cost of fuel gas and the relatively low electricity prices make oil and gas energy conservation projects quite different economically from those of industries in other regions and significantly impede energy conservation. Low return energy conservation prospects often have trouble competing for the limited funds available in the high risk oil and gas exploration and production industry.

Aside from cogeneration, there are a variety of energy conservation opportunities where more dialogue may improve the economic climate for mutually advantageous energy conservation.

Government regulations play significant roles in the use of flared gas and cogeneration. The inability of utilities to make money on energy conservation projects while their revenues from electricity sales decrease is a specific challenge to be resolved.

The report contains a number of suggestions for research, development and demonstration projects but the major area of research need relative to $CO_2$ reduction is the challenge of reducing thermal inputs to in-situ bitumen operation. Almost any improvement in that area will produce a major reduction in future $CO_2$ emissions.

## 1.4 CONCLUSIONS AND RECOMMENDATIONS

### 1.4.1 CONCLUSIONS

i) Based largely on Alberta government forecasts, $CO_2$ emissions due to Canadian oil and gas industry activities are anticipated to rise by about 22 percent from a level of just over 46 megatonnes in 1988 to 57 megatonnes by 2000. Sixty-two percent of the projected increase is due to increased in-situ bitumen production.

ii) All other industry sectors, except for oil pipelines, are anticipated to have somewhat higher $CO_2$ emissions than in 1988, due largely to more energy intensive production and transport.

iii) Economically attractive energy conservation and efficiency improvement activities have the potential to reduce oil and gas related $CO_2$ emissions by approximately 6 to 7 percent. This reduction will require a capital investment. (There are probably further undefinable savings available from a variety of site specific initiatives.)

iv) Cogeneration at gas plants and other industry facilities is not generally economic at this time but has major $CO_2$ reduction potential in the order of 12 percent of 1988 industry related $CO_2$ emissions.

v) An industry wide energy efficiency and $CO_2$ emission reporting system is essential to achieving an industry wide reduction program.

vi) Energy awareness and the many available energy conservation approaches should be highlighted by the upstream oil and gas industry organizations and internally in oil and gas companies.

vii) There are a number of oil and gas activities which warrant research and development and demonstration of new approaches to achieving energy efficiency with in-situ bitumen production being a prime candidate due to its growing role in $CO_2$ emissions.

### 1.4.2 RECOMMENDATIONS

- The upstream petroleum industry should develop an industry wide energy efficiency and $CO_2$ emission/utilization reporting system in conjunction with provincial oil and gas statistical organizations to provide a proactive approach to publicising the industry's commitment to energy conservation and $CO_2$ emission reduction.

- The upstream petroleum industry, government and professional organizations should promote demonstration projects, symposia and workshops to increase energy conservation and $CO_2$ reduction potential awareness.

- Ongoing dialogue should be developed by the upstream petroleum industry with governments and utilities relative to flare gas use, cogeneration, optimizing electrical utility demand side management programs, co-funding of demonstration projects and related management programs, regulatory, fiscal and technical issues.

- Corporate wide energy consciousness - awareness, monitoring, action - programs should be begun, or in many cases, expanded to provide the momentum necessary to achieve economically attractive energy efficiency and $CO_2$ emission reduction.

# 2.0 INTRODUCTION

## 2.1 GENERAL

Energy conservation reduces $CO_2$ emissions. This report examines energy conservation economics and resulting $CO_2$ impacts in the oil and gas industry.

The Canadian Petroleum Association is dedicated to developing enhanced energy and greenhouse gas awareness among its members. As part of its program, the CPA's $CO_2$ Control Options Task Group commissioned this study of the economic potential for energy conservation and related carbon dioxide ($CO_2$) emission reduction in Canadian oil and gas production operations. The emphasis is on production, pipelining and gas processing with drilling and surface mining of bitumen excluded. The study concentrates on "generic" - average -facilities, extrapolating the savings across the industry.

In the late 1970's, the U.S. Gas Processors Association developed a long check list of energy conservation opportunities. That document is still a good reference and has been updated by RTM as a separate stand alone guide to this report for use in Canada's oil and gas industry. The energy conservation options considered economical in this review are those that promise the most general use and economic potential across the industry. But at any given site, the options and their potential returns will vary, hence, the need for an operator to consider a longer list of options than those examined in detail in this study.

The committee members and their companies provided much insight and many examples of energy conservation. Likewise equipment vendors, electric utilities, provincial departments of energy and the Alberta Energy Resources Conservation Board were of appreciable help. However, the report's recommendations, comments and conclusions are those of RTM.

## 2.2 ECONOMIC CRITERIA

Each step for the reduction of energy use and $CO_2$ emissions was evaluated before and after income taxes and royalties. Escalation at 5 percent and a discount rate of 15 percent were used for both.

The CPA provided the following after tax/royalty factors (Appendix B) which approximate average industry rates to simplify the evaluation of the many energy conservation steps:

- Investment factor, after benefit from CCA .70
- Operating cost savings, after taxes .60
- Increased revenue from sales of volumes of fuel gas reductions after GCA, royalties and income taxes .45

An average electricity cost of 3.54¢/kWh was assumed and fuel gas was taken as $1.65/GJ.

The sensitivity of the conservation steps was tested in Appendix B where gas prices of $1.30 and $2.00 per GJ were also used. These also may be used to estimating the sensitivity to higher or lower royalties

# 3.0 BACKGROUND

## 3.1 PREAMBLE

Carbon dioxide is the principal greenhouse gas, contributing approximately 60 percent of the total global warming effect.[1] While this effect is essential to life on the planet, there are proposals to limit greenhouse gas emissions to prevent possible warmer climates in the future.

$CO_2$ emissions due to oil and gas operations in western Canada are very significant; for example, roughly 25 percent of Alberta's emissions, slightly above residential plus commercial related emissions, are contributed by oil and gas operations, and related electricity generation (excluding oil sands). While Alberta's per capita $CO_2$ emissions are above the national average (due in part to coal based electricity), it must be noted that these oil and gas operations provide fuels to much of Canada and adjacent areas of the U.S.

The oil and gas industry is very diverse with roughly 70,000 active wells as well as many gathering systems, compressor stations, gas processing plants, pump stations and pipelines across western Canada. Thus, consideration of reducing the industry's $CO_2$ related emissions involves a very broad range of facilities and potential initiatives.

Except for the $CO_2$ extracted from sour natural gas and then vented, $CO_2$ emissions resulting from oil and gas operations are due to the combustion of various gases in fields and at plants, and to the combustion of coal and, to a lesser extent, of natural gas for electricity generation. The $CO_2$ from sour gas is strictly dependant on the nature of gas being produced and cannot be considered a controllable variable other than as the recovered $CO_2$ may be used in enhanced oil production or otherwise dis-

---

1 "Climate Change, The IPCC Scientific Assessment", International Panel on Climate Control, page 61 (1990), reporting on a 100 year time horizon. A shorter period would show a somewhat lower percentage impact for $CO_2$.

posed of to underground formations. This study defers to other studies being coordinated by AOSTRA, the Alberta Department of Energy and other agencies with respect to $CO_2$ capture, purification and disposal.

This study thus has concentrated on economic approaches to reducing $CO_2$ emissions through energy conservation including reducing net electricity inputs to the oil and gas industry.

## 3.2 $CO_2$ EMISSION LEVELS

### 3.2.1 CURRENT EMISSIONS

Approximately 46 megatonnes of $CO_2$ were emitted in 1988 by oil and gas operations (and due to associated electricity requirements) in western Canada, exclusive of surface oil sands activities. Appendix A provides preliminary provincial and sectorial data, with an emphasis on Alberta as its industry contributes the bulk of such $CO_2$ (and as more detailed statistics were available). This study has assumed that current emissions are roughly the same as in 1988.

### 3.2.2 PROJECTED EMISSIONS WITHOUT ENERGY CONSERVATION

Based largely on 1990 Alberta Department of Energy and Alberta Energy Resources Conservation Board data, by the year 2000 western Canada oil and gas related $CO_2$ emissions are expected to increase to approximately 57 megatonnes, 22 percent above the current level assuming no energy efficiency improvements

By 2005, the emissions could reach 61 megatonnes. Over half of the increase is projected for in-situ bitumen production. Increased B.C. sour gas processing is another area with major increases projected. But virtually all industry sectors are estimated to have some increase, with only oil pipelines showing a decline due to reduced oil production.

### 3.2.3 ALBERTA DEPARTMENT OF ENERGY ESTIMATES

In late 1990 and early 1991, the Alberta Department of Energy released a study of the potential for reduction of Alberta $CO_2$ emissions - assuming a 10 year before tax payback - through energy conservation including cogeneration.

That study indicated that by 2005, a 2 percent reduction in oil and gas related $CO_2$ emissions could be achieved compared to 1988. The bulk of this reduction was assumed achieved by cogeneration at gas plants and electricity generation from gas now flared - both of these measures are very effective in backing out coal based electricity if economic.

The department's study was intended to indicate the ultimate potential for energy conservation/$CO_2$ emission reduction and should not be compared to the results of this study due to the greatly differing economic criteria used and market penetration criteria:

**Table 3.2.3-1**
**Comparison of Economic Bases and**
**Alberta Department of Energy Studies**

| Factor | This Study | Alberta Department of Energy 1990 Studies |
|---|---|---|
| **Economic Criteria** | | |
| • Basic | AFTER Tax and Royalty industry average rate of return in 1990<br>- with 5% escalation on costs and 15% discount factor. | BEFORE Tax and Royalty with 10 year simple capital payout.<br>- with no escalation<br>- with no discounting |
| • Alternates | - Higher and lower fuel gas costs to show impacts (Appendix B only) | |
| **Penetration of Energy Conservation Option** | Estimated for each measure based on payout, nature of option and affected equipment and other judgemental factors | 100% |

### 3.2.4 $CO_2$ RECOVERY AND DISPOSAL POTENTIAL

As noted above, other studies are examining $CO_2$ capture and utilization in enhanced oil recovery or disposal into a form not released to the atmosphere. At time of writing, the work being led by Alberta Oil Sands Technology and Research Authority (AOSTRA) on Enhanced Oil Recovery (EOR) and by the Alberta Department of Energy's Coal Research group on other approaches to $CO_2$ fixation were in progress and, hence, no measure of the potential for such disposal of oil and gas related $CO_2$ was available.

EOR projects themselves can result in $CO_2$ emissions when injected $CO_2$ is reproduced and not recaptured. But in 1990 the amount of such $CO_2$ emissions were only in the order of 0.02 megatonnes, about half of that being injected into the two small current $CO_2$ EOR projects - both figures neglected in the inventory of Appendix A.

### 3.2.5 $CO_2$ IN SALES GAS

Due to the use of more hydrogen sulphide ($H_2S$) selective solvents at sour gas plants, the amount of $CO_2$ in natural gas going to straddle plants is increasing, but the expected 0.05 volume percent increase will be largely captured and vented at such plants - very little more will move to markets outside Alberta.

## 3.3 $CO_2$ EMISSION FACTORS

This study has used certain factors from the previously noted Alberta Department of Energy studies for production of $CO_2$ from the combustion of various fuels:

- Natural Gas 49,700 tonnes per petajoule of contained energy
- Flared Gas 49,700 tonnes per petajoule of contained energy
- Diesel 70,700 tonnes per petajoule of contained energy

The correct flared gas factor may be higher as it is often raw gas richer in heavier hydrocarbons than the residue natural gas sold to the market place.

This study used a $CO_2$ emission factor of 0.88 kilotonnes per gigawatt hour of electricity delivered to customers, representative of Alberta's 1989 production before coal mining charges. Saskatchewan's average was about 1.01, but B.C. and Manitoba equivalents were near zero due to reliance on hydroelectricity. While lower than the Alberta Department of Energy's 1988 figure of 0.982, including mining, it is believed that 0.88 is reasonably representative of the $CO_2$ releases due to western Canadian oil and gas electricity consumption.

Trends in the electricity $CO_2$ factor are not well defined but emissions and the $CO_2$ factor are likely to decline by 2000.

While there is a definite need to restudy all $CO_2$ factors in further work, the above were considered satisfactory for this study, both in 1990 and later years.

# 4.0 ECONOMIC ENERGY CONSERVATION POTENTIAL

## 4.1 PREAMBLE

A 1979 U.S. Gas Processors Association Energy Conservation Check List provided many pages of energy conservation options from the design stage of a project through operations. An update was prepared in conjunction with this study to provide a long list from which a selection was made of those offering the most likely economic attractiveness on a broad basis across the oil and gas industry.[2]

The short listed options were examined to determine capital and operating costs, fuel gas savings and net electrical demand impacts. The net gas and electricity input changes were converted into net $CO_2$ reduction. The extent of the applicability of each short listed option was developed from available industry statistics and, finally, the likely penetration into the defined market was estimated, based on variations in that market and judgement of operator acceptance and utilization of the particular option.

Cogeneration and the potential use of flared gas for electricity were analyzed, although currently not economic under the prevailing economic and regulatory factors.

## 4.2 ECONOMIC ENERGY CONSERVATION MEASURES

From the long lists noted above and the many discussions leading to this report, a short list of attractive measures was selected and subjected to technical, economic and penetration analyses. Appendix B presents the individual analyses and composite tables.

Table 4.2-1 summarizes the thermal energy reduction groups of measures.

---

2 The revised check lists for both oil and gas are available from the CPA on request.

**Table 4.2-1**
**Economic Thermal Energy Measures**

| Industry Area | Measure Group | $CO_2$ Reduction $10^3$ tonnes/year | Capital Requirement Millions of 1990 Dollars | After Tax and Royalty Payout (a) years |
|---|---|---|---|---|
| Sour Gas Processing | Solvent Change (from DEA | 442 | 10.4 | 0.6 |
| Sour Gas Processing | Incinerator Fuel Reduction | 315 | 2.8 | 0.6 |
| Sour Gas Processing | Solvent Change (from MEA) | 293 | 5.0 | 0.5 |
| Oil Field | Added Heat Exchange | 275 | 13.6 | 3.4 |
| Oil/Gas Gathering | Field Htr Eff'y Improvement | 53 | 0.9 | 1.5 |
| Gas Gathering | Stripping Gas Reduction | 14 | 0.0 | 0.0 (b) |
| Total | | 1,392 | 32.7 | |

Notes: (a) With fuel gas @ $1.65/GJ and economic bases as in Appendix B, Section 3.3
(b) No capital or incremental operating cost.

The predominance of sour gas processing items is to be noted. Appendix B notes several other thermal items which ultimately did not prove generally economically attractive. Operators are encouraged to evaluate these opportunities as they relate to their specific operations.

Table 4.2-2 summarizes the electrical energy reduction group of measures.

**Table 4.2-2**
**Economic Electrical Energy Measures**

| Industry Area | Measure Group | $CO_2$ Reduction $10^3$ tonnes/year | Capital Requirement Millions of 1990 Dollars | After Tax and Royalty Payout years |
|---|---|---|---|---|
| General | Pump System Motors/Drives | 291 | 13.3 | 1.9 |
| Gas Gathering/ Processing | Compressor Motors/Drives | 225 | 1.9 | 0.3 |
| Oil Fields | Pump Jack PF Correction | 86 | 1.3 | 0.6 |
| Gas Processing | Aerial Cooler Changes | 78 | 4.5 | 2.5 |
| Total | | | 21.0 | |

Lighting changes are not shown above although reported in Appendix B and to some extent already underway at many sites although not identified as economical. If implemented as anticipated, they would further reduce $CO_2$ emissions by about 17,000 tonnes a year.

The above are by no means full lists of options economically viable today, but most other options have limited, albeit locally important, viability. To some extent some of such options are picked up in Sections 4.3 and 4.4 below.

## 4.3. SUPPLEMENTARY LISTS

During the study a variety of options, believed to have potential, were not quantified due to their very site specific nature and lack of detail available. Many such items are discussed in Appendix C with the following a brief listing:

- Thermal Energy Related
  - "Just to" specification products
  - Plant consolidation (with related plant shutdown)
  - Improved fired heater efficiencies
  - Optimize gathering system pipeline heating

- Electricity Consumption Related
  - Power factor correction
  - Upgraded control systems
  - Improved electricity distribution systems
  - Load shedding

As noted before there are many facility change options available to the designer and the operator. This study has considered only those anticipated to have broad application and to significantly contribute to industry wide $CO_2$ reduction. Thus, the significant potential of the supplementary items and other very site specific options has not been included in the estimated economic $CO_2$ reduction.

The U.S. Gas Processors Association 1979 check list and the revised lists developed in this study will assist operators and designers in identifying options for their facility, but each field and plant will have its own unique set of opportunities, hence, must develop its own check list.

## 4.4 SITE ENERGY AWARENESS PROGRAMS

The above sections have tended to concentrate on energy conservation measures involving some capital expenditures. However, there are many possibilities in every day operations that require no or very minimal capital.

From RTM experience in other industries and review of oil and gas operations, corporate wide and site specific operations oriented energy conservation programs can save in the order of 1 to 2 percent of energy inputs in their first two years with further annual savings in the 0.2 to 0.3 percent range. These savings are incremental to the major options discussed above in Section 4.2 and Appendix B.

Many of the options identified in Section 4.2 and Appendices B and C require ongoing energy consumption monitoring to insure that they continue effective. Such monitoring is logically fully integrated with the local energy conservation program which requires a periodic statistical base of energy inputs and efficiencies in any case.

For such savings, energy awareness and conservation must become a way of life at all levels of the organization.

- Local energy committees are suggested, using, for example, existing safety committees as guides.

- Corporate level support and rapport is another necessary component, insuring technical and administrative support.

- Key personnel with energy accounting, auditing, conservation and related communications and training responsibilities must be identified at each level and section of the organization.

## 4.5 COGENERATION AT GAS PLANTS

### 4.5.1 GENERAL

Most gas plants have the opportunity to take advantage of the high overall thermal efficiencies attainable with the generation of electricity combined with the use of the exhaust heat for process heating. However, there are at least four prerequisites.

- Firstly, the complexity of adopting cogeneration usually restricts use to installations with a usable heat load of at least 42 GJ/h.

- Secondly, to insure adequate reliability, standby steam capacity is needed and backup electricity must be available from the electrical distribution grid.

- Thirdly, there must be a demand for the electricity on site and/or by the local utility which is in reasonable balance with the waste heat requirement.

- Fourthly, for the economics of such cogeneration to be viable, the price must recognize the full value of the electricity on the electric power grid avoiding expansion of the grid and providing lower transmission losses.

The enhanced reliability of several cogeneration sources on the grid will also have to be recognized in the price for the cogeneration option to be viable and competitive with central coal fired electricity generating facilities. Credit should also be given to the reduced impact on the greenhouse effect of cogeneration facilities fueled with natural gas compared to coal fired generation facilities.

With the exception of high $H_2S$ content gas treating processes, the heat energy requirements of NGL fractionation and amine regeneration units generally exceeds their demand for electrical energy. Therefore an arrangement to sell power to the electricity utility distribution company is required. To make cogeneration economic, this arrangement must provide for the delivery to the utility of surplus electricity at the full cost of alternative electricity to the utility, at or above 5¢/kWh. Furthermore, the electric power grid must provide backup electricity to the gas plant. If standby generation equipment is required to provide adequate reliability, the extra capital cost makes most cogeneration projects uneconomic.

### 4.5.2 GAS PLANTS WITH HIGH SULPHUR RECOVERY

Gas plants which produce large quantities of sulphur, in theory at least, can be built or revamped to produce high pressure steam to generate electricity utilizing the low pressure exhaust heat in the process. However, most such plants have been designed to utilize the high pressure steam in relatively inefficient steam turbine drives for processing equipment with the exhaust heat often being excess to requirements. It is unlikely that any existing plant can be economically revamped because the change would involve the entire facility and the cost of shutdowns very costly. RTM therefore believes this option should be left for consideration in the design of new plants.

### 4.5.3 GAS PLANTS WITH LOW SULPHUR RECOVERY

Gas plants with low sulphur recovery due to low hydrogen sulphide ($H_2S$) concentration often have high carbon dioxide ($CO_2$) concentration. This combination results in high heat loads to regenerate the solvent without the large waste heat

produced when large quantities of sulphur are produced. Such plants are the prime candidates for cogeneration in the petroleum production sector.

Currently these plant generally have steam boilers which produce high pressure (circa 2000 kPa) steam for low efficiency steam turbine drives on pumps and fans. The exhaust from these turbines then provides the process heat for the regeneration of the acid gas solvent and other heat loads below 150°C.

Such plants could cogenerate electricity in either of two generic ways:

A. A natural gas fired gas turbine would drive an electricity generator. Some of the electrical output would be used to drive pumps and fans with the bulk being sold to the utility. A waste heat recovery steam generator would provide the process heat energy.

B. The high pressure steam from the boiler(s), including the stand-by boiler(s), would be expanded in a high efficiency steam turbine driving a generator to produce electricity to drive the pumps and fans with the exhaust providing the process heat.

Studies to date indicate that while either could be economic, option A promises the best economics. Note that in both cases, the low efficiency steam turbines are replaced by electric motors, but the steam drivers are left in place as backup to avoid any plant downtime due to cogeneration.

The first cogeneration facility being installed at a gas plant in western Canada is at Fort St. John, B.C. This facility will produce up to 105 MW of electricity and 3,000 kPa steam. The high pressure steam will be used to drive the steam turbines in that major gas processing complex with the exhaust steam being used for process heat. This will permit four steam boilers which produced up to 175,000 kg of steam per hour to be shutdown.

### 4.5.4 SENSITIVITIES

Because each gas plant will have unique requirements for electric power and heat, it is not meaningful to assume an average gas plant. Even the cogeneration heat recovery equipment would probably have to be custom designed. RTM has undertaken two studies of the economics of cogeneration at gas plants with many cases being examined. This work indicated that even the optimum cogeneration arrangements were uneconomic for the following reasons:

i) Surplus Power Production

Most plants require a good deal more heat than electricity which favours the low efficiency steam turbine drives used to drive pumps, blowers, etc. in gas plants explaining their widespread use. This problem vanishes if cogeneration becomes economic due to higher than now prevailing electricity sales value, when the surplus electricity is sold. In fact under this scenario, the steam drives can be economically converted to electric motors.

ii) Standby Capacity Investment

Cogeneration is very sensitive to investment inasmuch as the costs to service the investment are nearly twice the total operating costs including fuel. With the investment increasing by about 50% to provide 2/3 standby power generation for safe plant operation, the cost of surplus power increases by about one-third. Of course this problem would be largely offset if the utility company were to agree to provide backup electricity for the 100 percent electrical loads at the sales price for consumption without a demand charge and would recognize the high overall reliability of several cogeneration electricity sources.

iii) Fuel Gas Cost

Many plants can use fuel gas from connected fields at no direct cost or are able to purchase fuel gas from nearby fields (otherwise unable to get sales contracts) at very low prices. Fuel gas used from connected fields incurs no royalty payments, hence, the cost to the producer at most is the sales value of the fuel gas less an allowance for royalties.

The cost of fuel gas to a gas plant operator, if it is considered to be bottom of the reservoir gas, will not justify any meaningful fuel gas conservation. ("Bottom of the reservoir gas" is gas which if not used now as fuel gas, would not be sold until the reservoir was depleted to the point where it could not meet its peak contract sales demand). This can result in the discounted value of the fuel gas being a small fraction of its current sales value. This situation results when the fields supplying gas to a plant can produce more peak gas than the plant can sell under contract. As an individual field depletes, this situation of course disappears.

If gas sales prices increase faster than inflation, the economic drive to conserve fuel gas will naturally increase. Gas conservation is further frustrated as increased fuel gas use results in more byproducts (liquids and sulphur) being produced. This often results in fuel gas savings having a negative value.

While low fuel gas values frustrate fuel conservation in gas plants, it should be pointed out that they also contribute to lowering the cost of cogenerated electricity. In fact it can be shown that such low fuel gas values can make the generation of electricity without cogeneration competitive with coal fired thermal plants and hydroelectricity. This is particularly applicable to gas reserves remote from gas sales pipelines also usually remote from electric power generation facilities.

## 4.5.5 POTENTIAL FOR COGENERATION

i) In Sour Gas Plants in Western Canada

If the economic parameters were to change to justify cogeneration as noted above, there is tremendous potential for cogeneration at the sour gas plants in western Canada.

A rough estimate indicates that, at a 50/50 ratio of $CO_2$ and $H_2S$ in the acid gas removed from the raw gas, and allowing for 2.3 GJ of heat recovery per tonne of sulphur recovered, 6.36 kW of electricity could be generated per tonne of sulphur production with the heat recovered being used for amine regeneration at the rate of 20 MJ/h per litre per minute of highly loaded amine circulated. This indicates a theoretical potential of about 1,050 MW of electrical power at the current sulphur production rate of 6.1 million tonnes per year.

This study has not attempted an estimate of likely penetration but did note there is a significant decrease in the theoretical potential cogeneration at most plants due to the natural decline in productivity of the connected reserves.

Table 4.5.5-1 provides a brief assessment of a typical sour gas plant cogeneration project. It also notes the major reduction of $CO_2$ emissions across the gas and electrical supply sectors.

The 5.9 year after tax payout is not an acceptable rate of return in the oil and gas industry. In the particular case, the value of electricity sold to the grid would have to rise to a value of at least 6¢/kWh from the assumed 5¢ to provide a reasonable return. However, the plant operator must also factor in possible decline in gas processed and potential new technology, such as the newer solvents noted in Table 4.2-1 and Appendix B, changing his thermal energy needs. There are no economics in producing more electricity than that balanced with heat energy recovery requirements.

Extrapolated across the gas processing sector, the $CO_2$ reductions available from cogeneration could provide the largest contribution to $CO_2$ reduction of all oil and gas sector potential initiatives - but favourable economics are needed first. As much as 5.5 megatonnes per year of net $CO_2$ savings appear possible - 12 percent of current oil and gas related $CO_2$ emissions.

**Table 4.5.5-1**
**Example of Cogeneration Energy Savings**
**(90% Load Factor)**

| | UNIT | BEFORE | WITH COGEN |
|---|---|---|---|
| Electricity Generated | kWh/hour | 0 | 13,110 |
| Electricity Used | kWh/hour | 901 | 2,229 |
| Surplus Electricity | kWh/hour | 0 | 10,881 |
| Fuel Gas, GJ/d @ 26% Thermal Efficiency | GJ/d | 2,763 | 4,304 |
| Investment<br>Gas Turbine, Heat Recovery Boiler<br>HP Steam System, Transformers<br>Control Systems, Engineering<br>Owners Costs, Shutdowns for Tie-ins, Spares,<br>Conversions, Escalation, Interest | $ | 0 | 20,381,000 |
| Revenue from Surplus Electricity @ 5¢/kWh | $/year | 0 | 4,766,000 |
| Incremental Operating Costs | $/year | 0 | 1,732,000 |
| Cost of Incremental Fuel Gas @ $1.65/GJ | $/year | 0 | 759,000 |
| Operating Income | $/year | 0 | 2,275,000 |
| Payout Before Taxes | Years | --- | 18.56 |
| Payout After Taxes | Years | --- | N.P |
| $CO_2$ Balance | | | |
| Central Electrical Supply | kt/year | 6.2 | -75.5 |
| Gas Plant | kt/year | 45.1 | 70.3 |
| Total | kt/year | 51.3 | - 5.2 |
| Reduction | kt/year | --- | 56.5 |

* N.P. = No Payback

ii) Fractionation Plants in Western Canada

About 22.3 $10^3m^3/d$ of propane and butane are fractionated from propane or ethane and heavier mixes in western Canada, excluding the numerous stabilizers which produce pentanes plus only. The reboiler heat load required to deethanize, depropanize and debutanize is estimated to average 12.1 GJ/h per $10^3m^3/d$ or 270 GJ/h which has the theoretical potential to support 80 MW of electric power production by cogeneration.

Likely penetration is estimated to be less than 30 percent but could be better if Dow installs cogeneration with their major fractionation facility at Fort Saskatchewan.

iii) Heavy Oil and Bitumen Production

U.S. heavy crude oil fields, especially in California, are becoming major electricity generating sites through gas fired cogeneration. During the many discussions of this study, no specific economically viable Canadian heavy oil/ bitumen cogeneration projects were identified. However, the possibility of very major increases in in-situ bitumen production was noted previously and cogeneration could well fit into new schemes.

In-situ production operations often have wide swings in steam demands, unless balanced over a large number of patterns. Further study of the potential of "why" the apparently poor cogeneration economics exists in bitumen production appears warranted.

## 4.6 FLARING

### 4.6.1 PLANT FLARING

Gas flaring and occasionally venting occurs at plants and at wells. Most gas plants process non-associated gas and normally flare virtually no gas as they have the option

of shutting-in production during a plant upset. Plants processing associated gas cannot shut-in the oil production when the gas plant is down and hence, generally flare more gas than plants processing non-associated gas.

Overall gas plants report about 0.3% gas receipts are flared. The gas conservation authorities in western Canada do an effective job of monitoring gas flaring to see that the plants meet the operating license requirements which are about as stringent as reasonable operations permit.

### 4.6.2 FIELD FLARING

Very little gas is flared from gathering systems or central dehydration/ compression facilities handling non-associated gas. Near negligible releases to relieve pressure and for sampling are usually vented because flare systems have back pressure and could be unsafe for such purposes.

On the other hand, a large part of the gas flared in the field is associated gas from oil fields with and without gas conservation. In oil fields with gas conservation, gas is flared at batteries for a number of valid reasons. The gas is gathered at low pressures and is not dehydrated. In winter months, hydrate formation frequently curtails deliveries. Year round accumulation of condensed water and hydrocarbon liquids and oil carryover load the low pressure gas gathering systems with liquids and raise pressure drops until batteries go to flare. The effective gathering of low pressure gas is a continuous challenge to the operators. RTM estimates very little improvement can be accomplished without increasing the cost of gas conservation to the point where oil production would become uneconomic especially in small fields with low production per unit of area.

### 4.6.3 ELECTRICITY FROM FLARED ASSOCIATED GAS

The conservation of associated gas from many small oil fields has been shown to be uneconomic. With the value of natural gas forecast to increase very little more than inflation and since the state of the technology affecting gas conservation is very

mature, it is unlikely that these fields and new ones like them will prove to be candidates for gas conservation as now practised. However, if an arrangement were in place whereby this associated gas which would otherwise be flared could be used to power engines to drive generators to deliver electricity into the electric power grid a good portion of this gas could be conserved. In essence, the costs of gathering, compressing and processing this gas would be saved with some decrease in revenue.

It is probably not practicable to hook up units to the local electric power grid which produce less than 1,000 kW of electric power although sizes down to 300 kW should be examined. RTM estimates that there are 30 potential installations which could use gas from batteries (or several neighbouring batteries) flaring 5.6 $10^3m^3/d$ or more. This assumes that about half the batteries flaring this much gas would be suitably located on the distribution power grids. It is further estimated that the average such battery would flare 11.2 $10^3m^3/d$ of gas capable of generating 2,000 kW each, resulting in a total of 60 MW of generation. At 5¢ per kWh of electricity, about $\$30.13/10^3m^3$ of income would be realized after allowing a 15% internal rate of return on the investment over 10 years.

The potential reduction in flared gas is thus 30 x 11.2 $10^3m^3/d$ or 336 $10^3m^3/d$. The resulting $CO_2$ reduction would amount to approximately 0.23 megatonnes per annum.

**Table 4.6.3-1**
**Example of Flare Gas Conservation by Electricity Generation**

| Item | Units | Data |
|---|---|---|
| Average Size Generator | kW | 1,500 |
| Flare Gas Required | GJ/d | 509 |
| Investment | $ | 2,100,000 |
| Operating Cost | $/year | 147,000 |
| Electricity Sold (@ 90% load factor) @ 5¢/kWh | $/year | 591,000 |
| Cost Allowed for Fuel Gathering, etc @ 5¢/GJ | $/year | 84,000 |
| Operating Income | $/year | 360,000 |
| Payout Before Income Taxes | Years | 8.32 |
| Payout After Income Taxes | Years | N.P. |

* N.P. = No Payback

Two prototype flare gas generating systems are being considered with utilities possibly buying the gas at a low royalty and generating electricity at the site. Assuming they proceed, data from these projects should go a long way towards promoting further such systems. But as noted above, the number of flare gas situations large enough to contribute economically is limited.

## 4.7 ECONOMIC ENERGY CONSERVATION POTENTIAL

Not noted above is an ongoing NOVA pipeline system gas turbine replacement program that is anticipated to reduce $CO_2$ emission by approximately 0.2 megatonnes a year. With that item included, economically attractive measures to reduce $CO_2$ through energy conservation are summarized below.

**Table 4.7-1**
**Economic Energy Conservation and $CO_2$ Reduction**

| Item | $CO_2$ Emissions Megatonnes/Year |
|---|---|
| Base Oil and Gas $CO_2$ Emissions | 46.4 |
| Identified Measures | |
| • Thermal | -1.4 |
| • Electric | -0.7 |
| Energy Awareness Program | -0.5 |
| Flare Gas Recovery | -0.2 |
| NOVA Upgrade Program | -0.2 |
| Overall Savings | -3.0 (6.5% of base emissions) |

Cogeneration is not now economic and none is included above, although if and when economic, it offers major $CO_2$ reduction at central electricity generators based on coal, at small $CO_2$ "cost" in the oil and gas industry. The in-situ bitumen sector has only very minor improvements allowed above, yet is projected to produce the bulk of incremental oil and gas industry emissions.

The projected savings are believed to be conservative. Every lease and plant has energy reduction opportunities not quantified in this study. Options from the supplementary lists and many site specific options have not been included due to lack of data.

# 5.0 CHALLENGES TO ENERGY CONSERVATION

## 5.1 INTRODUCTION

For discussion, challenges to energy conservation have been broken down as follows:

i) Fuel gas value,
ii) Electricity cost and ease of use,
iii) Utility industry economics and policies,
iv) Oil and gas industry economics,
v) Oil and gas industry cycles,
vi) Government regulation,
vii) Awareness of energy conservation potential.

## 5.2 FUEL GAS VALUE

The value of incremental fuel gas varies from zero to that of sales gas depending upon the specific field and/or plant. A $1.65 per GJ value has been used as a base in this study and the sensitivity of energy conservation options to higher and lower fuel gas values is discussed in Appendix B.

Incremental fuel gas value will normally be near that of sales gas when the field or plant is operating at capacity. However, fuel gas is often available at low pressure and of a quality requiring much added processing for sales as gas and natural gas liquids. When a field is selling all the products it can, incremental fuel gas not reducing gas sales has a reduced value, as it would not be sold until the field could not meet its maximum sales volume. Furthermore, where byproducts are a large part of the revenue from the raw gas, excess use of fuel gas can increase revenues.

But even fuel gas priced near sales gas value is much less expensive than gas available to any industry in Canada or the U.S. beyond western Canada. Most energy conservation literature and examples are based on much higher priced gas than the values prevailing in Canada's oil and gas industry.

## 5.3 ELECTRICITY COST AND EASE OF USE

Western Canadian electricity costs are generally lower than those in central Canada and well below those in the U.S. Again, these differences must be noted when considering energy conservation examples from other areas.

Recent years have seen many electric driven gas compressor installations. But with similar cycle efficiencies gas drives are more energy and $CO_2$ efficient by a factor of about 2, compared to coal based electricity. Capital costs, reduced maintenance costs, reduced noise, easier integration into distributed control systems and unattended operation all favour electric drives. Gas drives offer better variable load capability. Motor drive capital costs are also equal or slightly lower than with gas.

Innovative electric utility provision of temporary on-site generation of electricity until power lines are built, and billing only during months of actual use are also contributing to increased use of electric motor driven compressors.

Higher electricity costs in the future and greenhouse gas concerns appear to promote a move back to gas drives in new applications. Several companies surveyed noted, however, that their preference would probably change only marginally, with at least small and remotely controlled high load factor installations still using electric drives.

## 5.4 UTILITY INDUSTRY ECONOMICS AND POLICIES

### 5.4.1 COGENERATION AND FLARE GAS USE

As discussed above, cogeneration at gas plants is not economic today except in special circumstances. The first such facility is being built at the Taylor, B.C. plant of Westcoast Energy with a capacity of approximately 105 MW of electricity with steam being used in gas processing. The value of electricity delivered to B.C. Hydro will be in the order of 3.5 cents per kWh, in 1990 terms. The Taylor project involves both Westcoast and CU Power, two utility companies. Cases examined in this study

indicate even higher prices are needed to support cogeneration at oil and gas facilities given normal industry economic criteria.

The levellized 4.2 to 5.2 cents per kWh of the Alberta Small Power Producer's program will attract some non oil and gas electricity projects but will not impact on the Alberta utilities overall generation needs. Surplus central generating capacity through 1996 and possibly as late as 2000 appears likely. Any significant cogeneration capacity would further delay the need for new capacity. As a "needs" test is required of any significant electricity project, the lack of need for added generation can be a major regulatory challenge to cogeneration. The prairie utilities have little more to offer than the voided cost of coal and minor operating credits, with some adjustment for reduced line losses in many cases.

Cogeneration projects are 2 to 4 times as $CO_2$ efficient as coal based electricity generation and, hence, have major $CO_2$ reduction potential.

Utilities prefer 15 to 20 year contracts for electricity purchase, a difficult challenge for the oil and gas industry given reserve declines and business and technology unknowns. There must be a productive use for the heat produced in cogeneration. The recent introduction of sour gas solvents with reduced regeneration heat requirements illustrates the technology risks inherent in cogeneration.

Small generation facilities are not important in the overall electricity system and tend to be an administration nuisance to utilities. However, flared gas use may have some economic situations even today (with special low provincial royalties). Such projects are even more CO2 reduction oriented than cogeneration as the rate of oil and gas $CO_2$ emissions remains unchanged and predominantly baseload coal electricity is backed out in Alberta and Saskatchewan.

### 5.4.2 WHEELING

Wheeling permits a producer with surplus generation capacity at one site to transfer the surplus to his needs to another site, thus lowering his overall electricity costs.

Regulatory impediments require discussion with the utilities and the Public Utility Board. Utilities are open to discussion on the transmission of electricity from one oil or gas site to another, and on equivalent alternates such as buy/sell arrangements.

### 5.4.3 DEMAND SIDE MANAGEMENT PROGRAMS

The various utilities are starting to develop programs to reduce future electrical demands through encouragement of more efficient use of electrical energy. B.C. Hydro is even subsidizing the conversion of electric heating to gas, which although counterproductive to $CO_2$ emissions in that province, postpones the need for new generating and transmission facilities.

However, compared to utilities in the U.S. and central Canada, the progress towards conservation and more efficient use of electricity has been slow in western Canada, apparently largely due to the lack of framework for the various utilities to share in the overall cost savings of such activities.

## 5.5 OIL AND GAS INDUSTRY ECONOMICS

Oil and gas producers are more oriented to high risk/high return ventures than low risk/low return energy conservation projects. Thus, economic criteria tend to require higher rates of return than might be the norm for energy conservation projects in other sectors of the economy.

The royalty structure has an adverse effect on energy conservation projects because the producer must put up the capital and operating costs but share the revenue from increased gas sales with the royalty owner. The gas cost allowance (GCA) for gas plants offsets the operating costs and part of the capital cost but is not allowed for wells and oil production properties.

Energy conservation is largely made up of numerous small items each offering a small improvement in overall economics while diverting management attention from bigger and more potentially profitable projects. The oil and gas industry is an example of

high risk venture orientation, and small low risk projects may not have comparable acceptance. On the other hand, in times of adversity for the industry there may not be money for energy conservation.

Third party financing of well defined energy conservation projects has been successfully employed in other industries where, for example, savings are shared with the owner. Such innovative approaches could be considered in the oil and gas industry to avoid tying up risk capital on such projects.

## 5.6 OIL AND GAS INDUSTRY CYCLES

Seasonal and daily gas production patterns and day of month oil production patterns greatly impact both on the applicability and efficiency of most energy conservation initiatives.

Of possibly greater importance, especially relating to cogeneration and flare gas use are longer term declines in throughputs at individual plants and fields. A brief analysis indicates substantial declines in cogeneration potential at many plants over time and a 10 year life at design capacity may not be uncommon for gas plant cogeneration projects.

These same declines make it difficult to "optimally" select and design energy conservation measures unless they have a very short payout.

## 5.7 GOVERNMENT REGULATIONS

As noted above, the B.C. cogeneration project illustrates the ability of processors/utilities and regulatory agencies to put together a major gas plant cogeneration project. Progress is also being made in Alberta towards possibly innovative royalty approaches to allow flared gas to be used in one or two small , less than 2.5 MW, demonstration generating facilities. Presumably if these proceed and operate satisfactorily, the innovative royalty arrangement will be extended to other projects and provinces.

In Alberta, the overall approval processes for cogeneration projects, at least over 2.5 MW are not well defined. The respective roles of the Alberta Energy Resources Conservation Board and Public Utilities Board on the review and approval of larger gas fuelled cogeneration projects supplying electricity to the provincial electrical grid have not been tried in practice. PUB approval is needed to insure that the costs can be rolled into the electrical rate base by the particular utility. However, of much greater importance is the need for the producer/processor and the utility to initially agree on terms acceptable to both before proceeding to the regulatory approval stage. The time involved in any necessary regulatory approvals must of course be weighed in the decision to install cogeneration facilities.

The regulatory agencies must also bless any innovative approaches to providing investor owned utilities revenue to offset Design Side Management (DSM) and other programs reducing electrical demands on utility generation facilities. As much innovation may be needed on the regulatory side as by the oil and gas and utility industries.

## 5.8 AWARENESS OF ENERGY CONSERVATION POTENTIAL

### 5.8.1 CORPORATE ORGANIZATION

This study noted few companies structured to promote energy consciousness throughout the organization. The current energy conservation pressures are due to environmental issues and unlike the 1970's, energy conservation is being led by company environmental groups in many cases. Secondment of operating personnel skilled in energy conservation appears common to such groups.

The depth of analysis needed to fully quantify savings given somewhat vague future system loads and seasonal variances can become very expensive. Hence, there is a tendency for shortcut calculations and use of direct vendor claims which often lead to overestimates of savings and, hence, poor energy conservation projects in retrospect. This challenge needs to be carefully considered in each company.

The development of greater energy consciousness requires full corporate commitment from the chief executive to each field hand with all necessary resources. One good current corporate example noted has energy coordinators in each division to provide local focus with a head office support group very actively involved in project design and analysis, communications, and feedback option evaluations, small scale test/demonstration projects and industry/utility/regulatory agency liaison.

### 5.8.2 AWARENESS

While a lack of understanding of the many options available is apparent on the part of many designers and operators, this is not seen as a major impediment given suitable corporate acknowledgement of, and appropriate organization to optimize, energy use, both for energy and environmental reasons. The development of energy consciousness and related technology focal points in each company's head office and an energy conservation mandate from the top down will create the needed awareness.

The CPA and industry technical associations also have roles to play in improving communications between industry members, utilities and others with new ideas and case results to share.

# 6.0 REPORTING

## 6.1 OBJECTIVES

Energy conservation equates to reduced $CO_2$ emissions both at oil and gas facilities and at electricity generating plants. The new Canadian Council of Ministers of the Environment NOX/VOC Management Plan calls for energy conservation and voluntary energy audits, as well as environmental audits, in order to reduce nitrogen oxide and volatile organic compound emissions. Such audits will be most applicable at the lease or plant level.

However, an oil and gas industry wide reporting system covering energy use and $CO_2$ emissions is strongly recommended as a means of providing ongoing inventories measuring the success of industry wide energy conservation activities with governments and the general public.

## 6.2 CANADIAN INDUSTRY PROGRAM FOR ENERGY CONSERVATION (CIPEC) EXAMPLE

While unfortunately not including oil and gas, fourteen other industry groups annually report on their progress towards targets set in 1975 to reduce energy consumption by 31 percent by 1995. By the end of 1989 average savings in the order of 29 percent were reported but the pace was slowing as the most cost effective measures appear to have been implemented in the various industries. The oil and gas industry has implemented a number of energy saving measures but has not consciously reported these reductions.

CIPEC's objectives to promote energy conservation by are stated as follows:

- Setting voluntary energy efficiency improvement goals,
- Reporting annually to government on issues and progress relative to achieving these goals,
- Increasing energy management awareness and techniques within the industry,

- Exchanging non-proprietary energy information for the common benefit,
- Maintaining effective industry-government dialogue.

The CIPEC program has been voluntary with data provided on a confidential basis. The voluntary nature and the imprecise definition of many of its industrial sectors cloud the usefulness of the accumulated data. The refinery sector, for example, while covering about 80 percent of Canada's refineries misses two of the large refineries but includes Syncrude and Suncor oil sand operations.[3] There are also some differences in reporting sector by sector. With only 3 pages of text and tables per industry group in the annual report, even as a communication tool, CIPEC does not appear to be an ideal example for oil and gas industry $CO_2$ reporting, other than as its objectives provide excellent targets for an oil and gas industry program.

## 6.3 REQUIREMENTS

### 6.3.1 REPORTING MECHANISM

A voluntary program will not achieve industry wide participation leaving many doubts as to the validity of the data produced, much as in the CIPEC example. A voluntary reporting program would also require the processing of up 20,000 responses unless participating companies each consolidated their own data into one company package, and even then up to 1,000 complex responses would be handled. Many companies do not now consolidate their data so the latter approach would add appreciable to industry's workload. In either case, a large, central organization would be required for the data processing and analysis.

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3 The current monthly ERCB yield and electricity purchase reporting by these two operations provides good bases for both energy and $CO_2$ emission historical monitoring, quite separate from the CIPEC program. Given relatively constant carbon hydrogen ratios for bitumen, synthetic crude oil and natural gas and a $CO_2$ emission factor for electricity purchases, overall resource utilization and $CO_2$ emissions are quickly calculated.

Extension of existing provincial agency reporting systems to incorporate the necessary incremental data for energy and $CO_2$ statistical reporting is a much simpler approach and one providing essential government and public confidence in the results. The mandatory aspect of such an approach will be a problem to many oil and gas companies. However, this study strongly recommends that the various provincial oil and gas industry reporting programs be used as a base for energy and $CO_2$ reporting.

An overall annual company and industry summary would be a useful and necessary addition to provide a gathering point for provincial and territorial statistics and a means of interpreting the data and oil and gas energy conservation activities from an industry perspective.

### 6.3.2 SECTORIAL BREAKDOWNS

A sectorial breakdown is essential for any reporting system particularly for use in the industry itself. Subject to further analysis the following breakdown is recommended - light crude oil, heavy crude oil, in-situ bitumen, gas gathering, gas processing, straddle plants, oil pipelines and gas pipelines. As noted above, the surface mining and bitumen upgrading operations already have a separate reporting system that can be readily adapted for energy efficiency and $CO_2$ emission reporting.

### 6.3.3 ENERGY CONSUMPTION VARIABLES

Each of these industry sectors would have its own energy balance showing all energy inputs, including electricity, as well as losses to, for example, flares. Electricity production at the lease or plant would also be covered.

Current provincial oil and gas production reporting does not collect data on electrical purchases or electricity sales or on purchased natural gas and other purchases of fuels for field use. In the latter category propane, gasoline and diesel are all used in varying quantities for non vehicle use. Except possibly for electricity, the lease/plant operator will normally have data at hand or readily available on extraneous energy inputs and any electricity sales to the grid.

Normally, utility company meter reading and billing procedures do not provide suitable month or year end data. Billings also tend to go to divisional or head offices. However, electrical consumption data are available via local meters at leases and plants, with a few exceptions where flat monthly charges are used. Reporting of electricity consumption at less than monthly frequency with at least an annual total at year's end, may prove acceptable, especially from small operations.

### 6.3.4 $CO_2$ PRODUCTION DATA

$CO_2$ recovered and vented at sour gas plants would be noted separately with transfers to enhanced oil recovery and/or other uses recorded.

### 6.3.5 $CO_2$ EMISSION CALCULATIONS

Factors will be needed for each industry sector to enable conversion of the energy input/output data into $CO_2$ emission equivalents. These factors will require periodic review and region or site specific factors may prove more applicable in some cases than industry wide averages. For example, electricity purchase related $CO_2$ will necessitate provincial averages.

### 6.3.6 PROVINCIAL SUMMARIES

It will be necessary to extend and revise current provincial statistical inputs and reporting to suit energy conservation and $CO_2$ needs. This requires an industry/government consensus on the appropriate sectors and the essential data for each.

The development of appropriate formats for changes to existing forms and for annual provincial agency reporting will be a major exercise. Manitoba, for example, will have to move to standardized reporting. There may also be a move by some provinces to add to current provincial monthly reports data now reported by industry, but not now published, such as flared gas in British Columbia.

Annual province by province sectorial energy/$CO_2$ balance statistical reports are envisaged, although built up largely from monthly statistical inputs. Some provinces may prefer monthly printouts to suit their overall oil and gas statistics reporting.

### 6.3.7 SUMMARY REPORTING

The purely statistical reports by province and territory might best be consolidated into an industry wide report. To the statistics - current and historic overall totals, sectorial totals, provincial totals - a narrative would be required to describe industry trends and other factors impacting an energy/$CO_2$ conservation, progress being made, energy conservation activity review and other narrative sections to provide industry, governments and the public with the facts they require. Appropriate graphics would be used to enhance the presentation. The report would be in the order to 8 to 12 pages and brochure sized.

## 6.4 IMPLEMENTATION

### 6.4.1 INDUSTRY/GOVERNMENT TASK TEAM

Generally, provincial representatives informally contacted during this study were quite receptive to the approach discussed above but major challenges in implementation were noted by one relative to the need to raise and extend many computer programs. In many cases, those contacted had been involved in related one time studies or had already considered revised reporting to better cover energy use and emission factors.

Another contact noted the need for a prior consensus between industry associations on a mandatory approach before any formal approach to the provinces. An industry working group is the first step in any case with agreement on the approach to be followed.

The provincial oil and gas statistical agencies meet every 2 years to consider their respective reporting systems and prospective changes. If timing is satisfactory, this

may provide an ideal forum for establishing a joint industry/government task force to define the work to be done.

### 6.4.2 DEFINE EXISTING REPORTS

A detailed review will be required of all provincial and territorial oil and gas reporting forms and procedures to define consistencies and inconsistencies relative to energy and $CO_2$ reporting. At the same time, the flexibility of the existing data reduction programs to change must be defined.

### 6.4.3 ADDITIONAL INPUT

Each industry sector will be examined by the joint Task Team to determine the minimum amount of new information and the appropriate format required in each province on a form by form basis. Generally, this study assumes monthly reporting of new data in parallel with existing reporting. But, as noted above, some data are not always available monthly and alternate approaches to reporting will be needed.

### 6.4.4 DATA ANALYSIS

Parallel with the consideration of new inputs and existing form revisions, the factors to be used to convert to standardized energy efficiency and $CO_2$ emission reporting must be developed. A "factor" sub task team appears warranted drawing on the work to date by the Alberta E.R.C.B. and Department of Energy. This team may itself be divided into groups looking separately at each industry sector and at provincial electricity supply $CO_2$ factors.

Additional input and data analysis procedures will be defined in each province and territory to determine the extent - cost, people, time - of software/or hardware changes that will be necessary at each agency.

An interactive approach appears necessary between the various provincial agencies, various industry committees and the Task Team in order to have agreement on the new/revised inputs and the calculations to be performed.

### 6.4.5 UPSTREAM REPORTING EFFORT

When the overall program is in place, there will be an annual accumulation of data from the various provinces, surveys of committees and upstream oil and gas member companies for energy conservation activities during the year and for rationale behind changes in unit energy consumption and/or $CO_2$ emissions in various oil and gas industry sectors. There will also be a writing and presentation effort to prepare drafts for circulation to industry committee members. Special feature articles on such activities as energy conservation committees, flare gas utilization and cogeneration would also be developed.

Each year the industry coordinating committee will also need to review the various factors in use by each province and acquire the latest electric utility $CO_2$ emission data. Occasional audits will also be needed of the results from provincial agency data reduction so that these contain no major errors.

## 6.5 REPORTING FACTORS

### 6.5.1 TRENDS

The proposed reporting system is to be built on lease and plant level data, but only industry sector or regional formal public reporting is suggested. The lease and plant operator will evaluate and monitor his own energy efficiency data as he inputs it to the respective provincial agencies.

Increasing gas exports plus declining light crude oil and increasing heavy crude oil/bitumen production will result in higher energy inputs and higher $CO_2$ emissions per unit of production. At the field level, changing formation conditions, demand

variations, weather patterns, the use of new technologies and many other factors impact on energy demands and on $CO_2$ emissions.

Local trends will not be picked up in the annual report other than as they are consistent with overall regional or sectorial trends. The industry wide report will, however, highlight global trends and major developments.

### 6.5.2 OTHER GREENHOUSE GASES

$CO_2$ is but one greenhouse gas, albeit the most important, and the recommended $CO_2$ report might be extended to cover activities and statistics on the other greenhouse gases. However, reliable statistics for such emissions as methane will be very difficult to develop due to the very large number of potential emission sources. It is recommended that the program start with $CO_2$ - other gases can be considered at a later date.

### 6.5.3 1990 BASELINE AND FORECASTS

The $CO_2$ emission inventories of Appendix A are preliminary and 1990 baseline $CO_2$ emissions inventories should be developed in parallel with the development of the recommended reporting system. The development of the baseline data will appreciably assist in the specification of new inputs to existing reporting and in the development of the appropriate factors for converting energy terms to $CO_2$ equivalents.

At the same time as such baseline emission inventories are developed, an oil and gas industry forecast of its $CO_2$ emissions would appear a very logical step to establish appropriate data for dialogue with government agencies and the public.

Energy conservation brings with it reduced $NO_x$, $SO_2$, CO and particulate emissions from oil and gas and electricity generating facilities. Such emissions and hydrocarbon emissions, covered in a separate CPA study, could be added to both baseline

inventories and forecasts to provide a consolidated oil and gas industry air emissions statistical base and forecast.

# 7.0 CONCLUSIONS AND RECOMMENDATIONS

## 7.1 RESEARCH AND DEVELOPMENT

Specific areas warranting research and/or development were noted as follows by contacts during the study:

i) More $CO_2$ efficient in-situ bitumen production is a key to significant reductions in oil and gas industry $CO_2$ reduction. (The potential in this area may be even greater than from cogeneration.)

ii) In conventional heavy crude and bitumen production there appears to be appreciable scope for more heat recovery.

iii) Demonstration of advanced approaches to field heater efficiency improvement is recommended.

iv) Demonstration of innovative approaches to flared gas utilization for electricity (or other purposes) is needed.

v) More energy efficient approaches to control and design of gas dehydration should be sought.

vi) Optimizing of compressor discharge pressures in various transmission systems warrants extensive study.

vii) Electrotechnologies such as microwave and infrared should be evaluated for small oil treaters and other field heating situations.

viii) Solar and wind power potential for remote metering and other small devices requires documentation and possibly enhanced application demonstrations.

The dissemination of information on new energy conservation technologies is essential to their use by all involved parties in the industry.

# APPENDIX A

## $CO_2$ Emission Data

# APPENDIX A

## $CO_2$ EMISSION DATA

Table A-1 is a preliminary estimate of oil and gas industry $CO_2$ emission for the year 1988, the reference year used in recent Alberta Department of Energy/Alberta Energy Resources Conservation Board studies and reports regarding $CO_2$ emission. Data for sources outside Alberta are very preliminary and largely 1990 based, but assumed to apply to 1988. Generally the emissions totals of the table are considered reasonably close to 1990 emission rates.

**Table A-1**
**Preliminary Estimate of Oil and Gas**
**Related $CO_2$ Emissions**
**Megatonnes**
**1988**

| | PROVINCES | | | | |
|---|---|---|---|---|---|
| **Source** | **B.C.** | **Alberta** | **Sask** | **Manitoba** | **Total** |
| Process | | | | | |
| Combustion | 0.6• | 20.5 | 1.6 | 0.1• | 22.8 |
| Electricity Purchase | 0.0* | 8.5 | 0.8• | 0.0* | 9.3 |
| Flaring | 0.3 | 4.6 | 0.4 | 0.1• | 5.4 |
| $CO_2$ from Gas Processing | 1.8 | 5.8 | 0.1 | — | 7.7 |
| Drilling & Misc. | 0.2• | 0.9 | 0.1 | — | 1.2 |
| Total | 2.7 | 40.3 | 2.9 | 0.2 | 46.4 |

Notes: • Very preliminary.
* $CO_2$ factor equals zero because assumed water power and (renewable) wood waste based.

Sources: Alberta Department of Energy/Alberta Energy Resources Conservation Board 1990 Studies and Reports for 1988
Saskatchewan Department of Energy and Mines
RTM File Data, Contacts and Preliminary Estimates

The next table provides a breakdown of Alberta emissions based on data from the Alberta Department of Energy's 1990 $CO_2$ Reduction studies. Certain of the data shown are taken from related support studies and thus may not agree with the formal presentations.

**Table A-2**
**1988 Alberta Oil and Gas Sector**
**Energy Data Before Econ**

| Source | Gas | | Diesel | | Electricity | | Total | Projected 2005 | % Increase |
|---|---|---|---|---|---|---|---|---|---|
| | PJ | $CO_2$ Equiv. MT | PJ | $CO_2$ Equiv. MT | GWh | $CO_2$ Equiv. MT | $CO_2$ MT | $CO_2$ MT | $CO_2$ MT |
| Oil | | | | | | | | | |
| Conventional and In-situ | | | | | | | | | |
| Heavy Crude | 31.9 | 1.59 | 13.2* | 0.93* | 2505 | 2.46 | 4.98 | 5.48 | 10 |
| Insitu Bitumen | 65.0 | 3.24 | — | — | 700 | 0.69 | 3.93 | 11.80 | 200 |
| | 96.9 | 4.83 | 13.2 | 0.93 | 3205 | 3.15 | 8.91 | 17.28 | 94 |
| Gas | | | | | | | | | |
| Field | 41.4 | 5.30 | — | — | | | | | |
| Gathering | 36.1 | 1.30 | — | — | 1955 | 1.92 | 15.69 | 16.32 | 4 |
| Plant | 144.3 | 7.17 | — | — | | | | | |
| Reprocessing | 10.4 | 0.51 | — | — | 2554 | 2.51 | 3.02 | 3.66 | 21 |
| | 232.2 | 14.28 | — | — | 4509 | 4.43 | 18.71 | 20.98 | 12 |
| $CO_2$ Venting | — | — | — | — | — | — | 5.80 | 6.81 | 17 |
| Pipelines | | | | | | | | | |
| Oil | — | — | — | — | 776 | 0.76 | 0.76 | 0.71 | -7 |
| Gas (other than Nova) | 6.5 | 0.32 | — | — | 165 | 0.16 | 0.48 | 0.85 | 77 |
| Nova | 21.2 | 1.05 | — | — | 0+ | 0+ | 1.05 | 1.41 | 34 |
| | 27.7 | 1.37 | — | — | 941 | 0.92 | 2.29 | 2.97 | 30 |
| Sub Total | 356.8 | 20.48 | 13.20 | 0.93 | 8655 | 8.50 | 29.91 | 41.23 | 38 |
| Flaring | 92.7 | 4.61 | — | — | — | — | 4.61 | 5.08 | 10 |
| Total MT | 449.5 | 25.09 | 13.20 | 0.93 | 8655 | 8.50 | 40.32 | 53.12 | 32 |

Notes:
* Oil and gas drilling
• 12.7 PJ of coal use shown in totals on natural gas equivalent basis
\+ (Small) Electricity inputs not available

Sources: Alberta Department of Energy, May 1990 Energy Related $CO_2$ Emissions 1988-2005 with Alberta Energy Resources Conservation Board and RTM

Before further work relative to $CO_2$ emission reductions, a new 1990 baseline is essential as is a CPA forecast of future $CO_2$ emissions.

# APPENDIX B

## Short List Option Data

# APPENDIX B

## SHORT LIST OPTION DATA

### B1.0 PREAMBLE

Data sheets are included for a short list of energy conservation items (options) that appeared likely to be economically attractive in at least certain oil and gas settings. Table 4.2-1 and 4.2-2 in the body of the report summarizes the various options and their potential for $CO_2$ reduction. Descriptions and typical economics follow in this Appendix B.

Each battery and plant have their own local economics relative to all items. Hence, the conclusions reached here for each option are not necessarily applicable at any given site. However, they are believed to be representative of the potential application for such options.

It is to be noted that cogeneration and flare gas utilization are not considered in Appendix B, as now they require utility financing or equivalent approaches to be economic.

### B2.0 DESCRIPTIONS, TERMINOLOGIES AND SUMMARY TABLES

In order to provide clarity to the following tables, the succeeding pertinent terms are defined:

### B2.1 DESCRIPTION AND TERMINOLOGIES

#### B2.1.1 Conservation Item

A specific area where energy conservation opportunities have been identified in which the effects of one or more conservation measures have been applied and summarized.

B2.1.2 Energy Conservation Measure

A single energy conservation idea applied to an energy "conservation item" recognizing that several measures could be applied to the same "conservation item".

B2.1.3 Measure Application

An estimate of the percent of the total number of existing units that a specific energy conservation measure could be applied to, recognizing that some units have already been modified while others may not be modifiable.

The application of the individual energy conservation measures varies within each specified conservation item. Not all of the energy conservation measures can be retrofitted to all the identified units within a specified conservation item. This is due to the unique differences between the individual units. Primary areas of consideration in the defining of measures application were:

(1) Equipment type
(2) Equipment adaptability
(3) Space availability
(4) Scale and size
(5) Existing equipment and installations
(6) Location

Each measure was considered separately with respect to the different areas and eliminated where the measure was not applicable. This gave a final number of units that were available to be fitted with the energy conservation measure in question.

B2.1.4 Measure Implementation

An estimate of the number of existing units that a specific energy conservation measure might be implemented, recognizing that not all operators are going to implement it for various reasons.

The implementation is a function of many interconnected factors and relations. In evaluating the implementation of the individual measures, the following areas were considered closely:

(1) Economics
(2) Current and projected government regulations
(3) Depleting fields
(4) $CO_2$ accounting
(5) Regulations and Approvals

Each measure (e.g. servicing and burner adjustment) of a specified item was first considered on an individual basis. By looking at a single measure, it is possible to estimate what effect on efficiency it will have if implemented; i.e. what the conservation measure efficiency improvement is. Knowing the present energy consumption, the projected savings based on the efficiency improvement, capital cost and operating costs, a payback period for the implementation of that measure was predicted.

The magnitude of the payback period is one of the economic parameters used in determining the implementation of each individual measure, but not the only one. The magnitude of capital cost is also of concern. Even if the payout is relatively small, eg. 1 year, the capital cost may be such that budgets will not allow for the spending of the initial investment. Operating cost is less of a concern since it is usually much less than the initial capital cost and can be paid by the economic savings acquired from the energy savings. Even though the economics of the operating cost is not of much concern, the potential for unavailability of qualified personnel to operate sophisticated new equipment was considered.

As fields and reserves deplete, less gas is produced from existing wells, If there are no wells available to replace those which are no longer able to produce, gas production will decrease. In these situations, the revenue attrition was considered and its effect on payout periods. If it was thought that a field may not be in existence long enough to meet the required payout, the implementation would severely be effected, unless other criteria restored the balance (e.g. government regulation, field consolidation).

The primary objective of energy conservation is to lower the operating cost for energy inputs which at the same time reduce the volume of $CO_2$ that is emitted into the atmosphere. Savings can be considered in a number of ways, each supplying additional data for making conclusions as to what the final implementation of a single measure may be. These are as follows:

(1) The overall magnitude of the $CO_2$ reduction due to the implementation of a single measure.
(2) The size of the reduction with respect to the capital cost and payout periods.

B2.1.5 Overall Penetration

The projected percentage of the overall effect of the application and implementation of one or more applied measures to an energy conservation item. The concept of diminishing return is used in determining this projection.

In determining the overall penetration of an individual item (e.g. line heater efficiency improvement), the interaction between implemented measures must be taken into account. This is referred to as the concept of "diminishing returns". As each measure is added to an item, the amount of available potential energy savings is diminished by the amount equal to the difference between the original potential energy savings and the energy savings of the implemented measure. The sequence that the measures are implemented also play a significant role. A measure, application or implementation that has a low efficiency improvement

may be particularly attractive if the potential energy saving is very high (ie. low efficiency improvement per item, but large number of items), but not so attractive if the potential energy savings have been diminished by previously implemented measures.

B2.1.6 Conservation Measure Efficiency Improvement

The projected percent efficiency improvement of an energy conservation item if a single energy conservation measure is applied.

B2.1.7 Conservation Item Efficiency Improvement

The projected total percent efficiency improvement of the overall effect of all of the applied measures to an energy conservation item. Concept of diminishing returns is used in determining this projection.

## B2.2 SUMMARY TABLES

List of Tables

| Table Number | Table Name |
|---|---|
| B.2.2.1 | Thermal Energy Conservation Summary - Per Unit |
| B.2.2.2 | Electrical Energy Conservation Summary - Per Unit |
| B.2.2.3 | Thermal Energy Conservation Summary - Industry Wide |
| B.2.2.4 | Electrical Energy Conservation Summary - Industry Wide |

# TABLE B2.2.1
# THERMAL ENERGY CONSERVATION SUMMARY - PER UNIT

Before Tax

| No. | Measure | Energy Type | Efficiency Improve. (%) | Energy Conserved per Unit (F=PJ/yr) (E=GWh/yr) | Differential Capital Cost per Unit (10^3 $) | Gross Economic Savings per Unit (10^3 $/yr) | Differential Operating Cost per Unit (10^3 $/yr) | Net Economic Savings per Unit (10^3 $/yr) | CO2 Conserved per Unit (kt/yr) | Total CO2 Conseved per Unit (kt/yr) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Stripping Gas Reduction | Fuel | 100.00% | 0.01 | 0.00 | 16.52 | 0.00 | 16.52 | 0.50 | 0.50 |
| 2 | Sulfur Inc. Fuel Gas Red'n | Fuel | 38.70% | 0.19 | 100.00 | 319.95 | 30.00 | 289.95 | 9.64 | 9.64 |
| | - Better Comb. Air Control | Fuel | 23.70% | 0.12 | 100.00 | 195.94 | 10.00 | 185.94 | 5.90 | |
| | - Reduced Stack Temp. | Fuel | 15.00% | 0.08 | 0.00 | 124.01 | 20.00 | 104.01 | 3.74 | |
| 3 | MEA to MDEA | F/E | N/A | N/A | 480.00 | 883.89 | -400.00 | 1283.89 | 27.15 | 27.15 |
| | - Fuel gas requirements | Fuel | 47.80% | 0.60 | N/A | 983.51 | -400.00 | N/A | 29.62 | |
| | - Electrical requirements | Elec | 0 | -2.81 | N/A | -99.62 | 0.00 | N/A | -2.48 | |
| 4 | DEA to MDEA | F/E | N/A | N/A | 480.00 | 822.80 | -400.00 | 1022.80 | 19.51 | 19.51 |
| | - Fuel gas requirements | Fuel | 41.60% | 0.46 | N/A | 764.65 | -400.00 | N/A | 23.03 | |
| | - Electrical requirements | Elec | 0 | -4.01 | N/A | -141.85 | 0.00 | N/A | -3.53 | |
| 5 | Heater Eff. Improv. | Fuel | 30.00% | 0.00 | 0.15 | 0.30 | 0.10 | 0.20 | 0.01 | 0.01 |
| | - Servicing and Burner Adjust | Fuel | 20.00% | 0.00 | 0.00 | 0.20 | 0.10 | 0.10 | 0.01 | |
| | - Combustion Air Preheat | Fuel | 15.00% | 0.00 | 1.00 | 0.15 | 0.00 | 0.15 | 0.00 | |
| | - Burner Sizing | Fuel | 20.00% | 0.00 | 0.15 | 0.20 | 0.00 | 0.20 | 0.01 | |
| | - Instr'n and Burner Control | Fuel | 20.00% | 0.00 | 1.00 | 0.20 | 0.10 | 0.10 | 0.01 | |
| | - Damper Controls | Fuel | 10.00% | 0.00 | 2.00 | 0.10 | 0.20 | -0.10 | 0.00 | |
| | - Turbulators | Fuel | 5.00% | 0.00 | 1.00 | 0.05 | 0.00 | 0.05 | 0.00 | |
| | - Burner Replacement | Fuel | 20.00% | 0.00 | 2.50 | 0.20 | 0.25 | -0.05 | 0.01 | |
| 6 | Added Field Heat Exchange | | | | | | | | | |
| | - Fld htr-treater exh't recovery | Fuel | 25.00% | 0.00 | 6.00 | 4.02 | 0.60 | 3.42 | 0.12 | 0.12 |
| 7 | Waste Heat Recovery | | | | | | | | | |
| | - Eng. exh't excn. for bldg ht | Fuel | 15.00% | 0.00 | 10.00 | 2.06 | 1.00 | 1.06 | 0.06 | 0.06 |
| 8 | Gas Eng. Fuel Eff Improv (75 hp+) | | | | | | | | | |
| | - Retrofit system on exist'g units | Fuel | 10.00% | 0.00 | 30.00 | 2.75 | 0.00 | 2.75 | 0.08 | 0.08 |
| 9 | Optimize Pipeline Pressures | Fuel | N/A | 0.03 | 2479.00 | 49.38 | 0.00 | 49.38 | 1.49 | 1.49 |
| | - Initial Design | Fuel | 9.30% | 0.00 | 889.00 | 4.25 | 0.00 | 4.25 | 0.13 | |
| | - Looping lines in declining flds | Fuel | 24.70% | 0.03 | 1590.00 | 45.13 | 0.00 | 45.13 | 1.36 | |
| 10 | Hydrate Control System | Fuel | 100.00% | 0.00 | 1.20 | 1.05 | 2.20 | -1.15 | 0.03 | 0.03 |
| | - Dehydrators | Fuel | 88.00% | 0.00 | 50.00 | 0.92 | 5.00 | -4.08 | 0.03 | |
| | - Dry Dessicant | Fuel | 70.80% | 0.00 | 200.00 | 0.74 | 2.65 | -1.91 | 0.02 | |
| | - Glycol Injector/Recovery | Fuel | 88.40% | 0.00 | 28.00 | 0.93 | 2.65 | -1.72 | 0.03 | |
| | - Methanol Injection | Fuel | 100.00% | 0.00 | 1.00 | 1.05 | 2.20 | -1.15 | 0.03 | |
| 11 | Elec. Trac. vs. Steam Trac. | F/E | N/A | N/A | 77.21 | -9.91 | -0.12 | -9.80 | 0.00 | 0.00 |
| | - Steam/Glycol | Fuel | N/A | 0.00 | 0.00 | 3.09 | 2.20 | 0.89 | 0.09 | |
| | - Electrical Tracing | Elec | N/A | 0.37 | 77.21 | 13.00 | 2.32 | 10.68 | 0.32 | |
| | | | | | | | | | Total | 58.58 |

# TABLE B2.2.2
# ELECTRICAL ENERGY CONSERVATION SUMMARY - PER UNIT

Before Tax

| No | Measure | Energy Type | Efficiency Improve. (%) | Energy Conserved per Unit (E=GWh/yr) | Differential Capital Cost per Unit (10^3 $) | Gross Economic Savings per Unit (10^3 $/yr) | Differential Operating Cost per Unit (10^3 $/yr) | Net Economic Savings per Unit (10^3 $/yr) | CO2 Conserved per Unit (kt/yr) | Total CO2 Conserved per Unit (kt/yr) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Compressors (75 hp +) | Elec | 16.00% | 0.88 | 6.50 | 31.15 | 0.00 | 31.15 | 0.77 | 0.77 |
| | - Energy Efficient Motors | Elec | 1.00% | 0.06 | 0.50 | 1.95 | 0.00 | 1.95 | 0.05 | |
| | - Variable Speed Drives | Elec | 15.00% | 0.83 | 6.00 | 29.21 | 0.00 | 29.21 | 0.73 | |
| | - Auto Unloaders | Elec | 10.00% | 0.55 | 2.00 | 19.47 | 0.00 | 19.47 | 0.48 | |
| 2 | Pump Systems | Elec | 17.58% | 0.08 | 3.30 | 2.90 | 0.00 | 2.90 | 0.07 | 0.07 |
| | - Energy Efficient Motors | Elec | 2.58% | 0.01 | 0.30 | 0.43 | 0.00 | 0.43 | 0.01 | |
| | - Variable Speed Drives | Elec | 15.00% | 0.07 | 3.00 | 2.47 | 0.00 | 2.47 | 0.06 | |
| 3 | Aerial Coolers | Elec | 69.65% | 0.05 | 2.30 | 1.62 | 0.00 | 1.62 | 0.04 | 0.04 |
| | - Energy Efficient Motors | Elec | 4.65% | 0.00 | 0.30 | 0.11 | 0.00 | 0.11 | 0.00 | |
| | - Variable Speed Drives | Elec | 65.00% | 0.04 | 2.00 | 1.51 | 0.00 | 1.51 | 0.04 | |
| 4 | Lighting (per plant) | Elec | 25.00% | 1.26 | 172.40 | 44.45 | 0.00 | 44.45 | 1.10 | 1.10 |
| | - Red. Ext. Ltg levels in Lrg Pits. | Elec | 25.00% | 1.17 | 160.00 | 41.35 | 0.00 | 41.35 | 1.03 | |
| | - Red. Ext. Ltg levels in Med Pits. | Elec | 25.00% | 0.08 | 12.00 | 3.00 | 0.00 | 3.00 | 0.07 | |
| | - Red. Ext. Ltg levels in Sml Pits. | Elec | 25.00% | 0.00 | 0.40 | 0.10 | 0.00 | 0.10 | 0.00 | |
| 5 | Pump Jacks | Elec | 23.00% | 0.02 | 5.25 | 0.76 | 0.00 | 0.76 | 0.02 | 0.02 |
| | - Power Factor Correction | Elec | 20.00% | 0.02 | 0.25 | 0.67 | 0.00 | 0.67 | 0.02 | |
| | - Proper Connected Motor Size | Elec | 3.00% | 0.00 | 5.00 | 0.10 | 0.00 | 0.10 | 0.00 | |
| 6 | Lighting (per fixture) | Elec | 42.38% | 0.00 | 0.99 | 0.05 | 0.00 | 0.05 | 0.00 | 0.00 |
| | - Repl. Incond. with a HPS Lamp | Elec | 50.00% | 0.00 | 0.98 | 0.06 | 0.00 | 0.06 | 0.00 | |
| | - Repl. Merc. Vap. with a HPS lamp | Elec | 34.00% | 0.00 | 1.01 | 0.04 | 0.00 | 0.04 | 0.00 | |
| 7 | Pressure Reducion Energy Use | Elec | 15.00% | 0.22 | 350.00 | 7.81 | 17.50 | -9.69 | 0.19 | 0.19 |
| | | | | | | | | | Total | 2.21 |

# TABLE B2.2.3
# THERMAL ENERGY CONSERVATION SUMMARY - INDUSTRY WIDE

Before Tax

| No | Measure | Energy Type | Total Ind. Wide Engy Consumpt. (F=PJ/yr) (E=GWh/yr) | Total # of Units | Overall Penetr'n Applic'n (%) | Implem'n (%) | Efficiency Improve. (%) | Energy Conserved Projected (F=PJ/yr) (E=GWh/yr) | Differential Capital Cost Projected (10^6 $) | Gross Economic Savings Projected (10^6 $/yr) | Differential Operating Cost Projected (10^6 $/yr) | Net Economic Savings Projected (10^6 $/yr) | Cap. Cost/ kt CO2 Reduct./yr Projected ($/kt/yr) | CO2 Conserved Projected (kt/yr) | Total CO2 Conserved Projected (kt/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Stripping Gas Reduction | Fuel | 0.70 | 70 | 100.00% | 40.00% | 100.00% | 0.28 | 0.00 | 0.46 | 0.00 | 0.46 | 0 | 13.94 | 13.94 |
| 2 | Sulfur Inc. Fuel Gas Red'n | Fuel | 28.06 | 56 | 58.44% | | 38.70% | 6.35 | 2.80 | 10.49 | 1.09 | 9.40 | 8865 | 315.86 | 315.39 |
| | - Better Comb. Air Control | Fuel | 28.06 | 56 | 100.00% | 50.00% | 23.70% | 3.32 | 2.80 | 5.49 | 0.28 | 5.21 | 16944 | 165.25 | |
| | - Reduced Stack Temp. | Fuel | 28.06 | 56 | 80.00% | 90.00% | 15.00% | 3.03 | 0.00 | 5.00 | 0.81 | 4.19 | 0 | 150.61 | |
| 3 | MEA to MDEA | F/E | 49.88 | 40 | 27.00% | | N/A | N/A | 4.97 | 9.55 | -4.32 | 13.87 | 16944 | 293.20 | 293.20 |
| | - Fuel gas requirements | Fuel | 49.88 | 40 | 90.00% | 30.00% | 47.80% | 6.44 | N/A | 10.62 | -4.32 | N/A | N/A | N/A | |
| | - Electrical requirements | Elec | 0.00 | 40 | 90.00% | 30.00% | 0 | -30.39 | N/A | -1.08 | 0.00 | N/A | N/A | N/A | |
| 4 | DEA to MDEA | F/E | 93.58 | 84 | 27.00% | | N/A | N/A | 10.43 | 14.13 | -9.07 | 23.20 | 23582 | 442.40 | 442.40 |
| | - Fuel gas requirements | Fuel | 93.58 | 84 | 90.00% | 30.00% | 41.60% | 10.51 | N/A | 17.34 | -9.07 | N/A | N/A | N/A | |
| | - Electrical requirements | Elec | 0.00 | 84 | 90.00% | 30.00% | 0 | -90.88 | N/A | -3.22 | 0.00 | N/A | N/A | N/A | |
| 5 | Heater Eff. Improv. | Fuel | 7.07 | 11526 | 50.00% | | 30.00% | 1.06 | 0.86 | 1.75 | 0.58 | 1.17 | 16393 | 52.73 | 52.73 |
| | - Servicing and Burner Adjust | Fuel | 7.07 | 11526 | 100.00% | 65.00% | 20.00% | 0.92 | 0.00 | 1.52 | 0.75 | 0.77 | 0 | 45.70 | |
| | - Combustion Air Preheat | Fuel | 7.07 | 11526 | 100.00% | 20.00% | 15.00% | 0.21 | 2.31 | 0.35 | 0.00 | 0.35 | 218579 | 10.55 | |
| | - Burner Sizing | Fuel | 7.07 | 11526 | 90.00% | 40.00% | 20.00% | 0.51 | 0.62 | 0.84 | 0.00 | 0.84 | 24590 | 25.31 | |
| | - Instr'n and Burner Control | Fuel | 7.07 | 11526 | 100.00% | 10.00% | 20.00% | 0.14 | 1.15 | 0.23 | 0.12 | 0.12 | 163934 | 7.03 | |
| | - Damper Controls | Fuel | 7.07 | 11526 | 100.00% | 0.00% | 10.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | - Turbulators | Fuel | 7.07 | 11526 | 100.00% | 0.00% | 5.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | - Burner Replacement | Fuel | 7.07 | 11526 | 100.00% | 0.00% | 20.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| 6 | Added Field Heat Exchange | | | | | | | | | | | | | | |
| | - Fld htr-treater exh't recovery | Fuel | 65.50 | 6727 | 75.00% | 45.00% | 25.00% | 5.53 | 13.62 | 9.12 | 1.36 | 7.76 | 49595 | 274.67 | 274.67 |
| 7 | Waste Heat Recovery | | | | | | | | | | | | | | |
| | - Eng. exh't exch. for bldg ht | Fuel | 36.21 | 4345 | 90.00% | 5.00% | 15.00% | 0.24 | 1.98 | 0.40 | 0.20 | 0.21 | 160963 | 12.15 | 12.15 |
| 8 | Gas Eng. Fuel Eff Improv (75 hp+) | | | | | | | | | | | | | | |
| | - Retrofit system on exist'g units | Fuel | 72.42 | 4345 | 90.00% | 10.00% | 10.00% | 0.65 | 11.73 | 1.08 | 0.00 | 1.08 | 362171 | 32.39 | 32.39 |
| 9 | Optimize Pipeline Pressures | Fuel | N/A | 550 | 0.00% | | N/A | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | 0.00 |
| | - Initial Design | Fuel | 15.23 | 550 | 20.00% | 0.00% | 9.30% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | - Looping lines in depleting flds | Fuel | 60.91 | 550 | 90.00% | 0.00% | 24.70% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| 10 | Hydrate Control System | Fuel | 3.05 | 4799 | 0.00% | | 100.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | 0.00 |
| | Dehydrators | Fuel | 3.05 | 4799 | 20.00% | 0.00% | 88.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | Dry Desiccant | Fuel | 3.05 | 4799 | 80.00% | 0.00% | 70.80% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | Glycol Injection/Recovery | Fuel | 3.05 | 4799 | 85.00% | 0.00% | 88.40% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | Methanol Injection | Fuel | 3.05 | 4799 | 90.00% | 0.00% | 100.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| 11 | Elec. Trac. vs. Steam Trac. | F/E | N/A | 550 | 0.00% | | N/A | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | 0.00 |
| | Steam/Glycol | Fuel | 1.03 | 550 | 90.00% | 0.00% | N/A | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | Electrical Tracing | Elec | 202.00 | 550 | 90.00% | 0.00% | N/A | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | |
| | | | | | | | | | | | | | | Total | 1436.86 |

# TABLE B2.2.4
# ELECTRICAL ENERGY CONSERVATION SUMMARY - INDUSTRY WIDE
Before Tax

| No | Measure | Energy Type | Total Ind. Wide Engy Consumpt. (F=PJ/yr) (E=GWh/yr) | Total # of Units | Overall Penetr'n Applic'n (%) | Implem'n (%) | Efficiency Improve. (%) | Energy Conserved Projected (F=PJ/yr) (E=GWh/yr) | Differential Capital Cost Projected (10^6 $) | Gross Economic Savings Projected (10^6 $/yr) | Differential Operating Cost Projected (10^6 $/yr) | Net Economic Savings Projected (10^6 $/yr) | Cap. Cost/ kt CO2 Reduct /yr Projected ($/kt/yr) | CO2 Conserved Projected (kt/yr) | Total CO2 Conserved Projected (kt/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Compressors (75 hp +) | Elec | 2497.00 | 454 | 64.00% | | 16.00% | 255.69 | 1.89 | 9.05 | 0.00 | 9.05 | 8394 | 225.01 | 225.01 |
| | - Energy Efficient Motors | Elec | 2497.00 | 454 | 80.00% | 80.00% | 1.00% | 15.96 | 0.15 | 0.57 | 0.00 | 0.57 | 10331 | 14.06 | |
| | - Variable Speed Drives | Elec | 2497.00 | 454 | 80.00% | 80.00% | 15.00% | 239.71 | 1.74 | 8.49 | 0.00 | 8.49 | 8264 | 210.95 | |
| | - Auto Unloaders | Elec | 2497.00 | 454 | 80.00% | 80.00% | 10.00% | 159.81 | 0.58 | 5.66 | 0.00 | 5.66 | 4132 | 140.63 | |
| 2 | Pump Systems | Elec | 2349.00 | 5042 | 80.00% | | 17.58% | 330.36 | 13.31 | 11.69 | 0.00 | 11.69 | 45786 | 290.72 | 290.72 |
| | - Energy Efficient Motors | Elec | 2349.00 | 5042 | 100.00% | 80.00% | 2.58% | 48.48 | 1.21 | 1.72 | 0.00 | 1.72 | 28362 | 42.67 | |
| | - Variable Speed Drives | Elec | 2349.00 | 5042 | 100.00% | 80.00% | 15.00% | 281.88 | 12.10 | 9.96 | 0.00 | 9.96 | 48783 | 248.05 | |
| 3 | Aerial Coolers | Elec | 212.98 | 3240 | 60.00% | | 69.65% | 89.00 | 4.47 | 3.15 | 0.00 | 3.15 | 57087 | 78.32 | 78.32 |
| | - Energy Efficient Motors | Elec | 212.98 | 3240 | 100.00% | 60.00% | 4.65% | 5.94 | 0.58 | 0.21 | 0.00 | 0.21 | 111533 | 5.23 | |
| | - Variable Speed Drives | Elec | 212.98 | 3240 | 100.00% | 60.00% | 65.00% | 83.06 | 3.89 | 2.94 | 0.00 | 2.94 | 53192 | 73.09 | |
| 4 | Lighting (per plant) | Elec | 100.22 | 550 | 20.00% | | 25.00% | 5.01 | 0.69 | 0.18 | 0.00 | 0.18 | 156031 | 4.41 | 4.41 |
| | - Red. Ext. Lt'g levels in Lrg Plts. | Elec | 84.10 | 18 | 100.00% | 20.00% | 25.00% | 4.20 | 0.58 | 0.15 | 0.00 | 0.15 | 155666 | 3.70 | |
| | - Red. Ext. Lt'g levels in Med Plts. | Elec | 10.51 | 31 | 100.00% | 20.00% | 25.00% | 0.53 | 0.07 | 0.02 | 0.00 | 0.02 | 160855 | 0.46 | |
| | - Red. Ext. Lt'g levels in Sml Plts. | Elec | 5.62 | 501 | 100.00% | 20.00% | 25.00% | 0.28 | 0.04 | 0.01 | 0.00 | 0.01 | 162199 | 0.25 | |
| 5 | Pump Jacks | | | | | | | | | | | | | | |
| | - Power Factor Correction | Elec | 2726.00 | 29016 | 90.00% | 20.00% | 20.00% | 98.14 | 1.31 | 3.47 | 0.00 | 3.47 | 15120 | 86.36 | 86.36 |
| 6 | Lighting (per fixture) | Elec | 143.50 | 42500 | 28.53% | | 42.38% | 17.35 | 10.90 | 0.61 | 0.00 | 0.61 | 785347 | 15.27 | 15.27 |
| | - Repl. Incond. with a HPS Lamp | Elec | 75.12 | 22883 | 50.00% | 80.00% | 50.00% | 15.02 | 8.92 | 0.53 | 0.00 | 0.53 | 675009 | 13.22 | |
| | - Repl. Merc. Vap. with a HPS lamp | Elec | 68.36 | 19817 | 50.00% | 20.00% | 34.00% | 2.32 | 1.97 | 0.08 | 0.00 | 0.08 | 963507 | 2.05 | |
| 7 | Pressure Reduction Energy Use | Elec | 819.00 | 557 | 50.00% | 0.00% | 15.00% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 | 0.00 | 0.00 |
| | | | | | | | | | | | | | | Total | 700.09 |

## B3.0 ENERGY CONSERVATION SUMMARY

### B3.1 $CO_2$ CONVERSION FACTORS

#### B3.1.1 Natural Gas

The gas consumption was treated as the consumption of methane. The conversion factor by Alberta Department of Energy for $CO_2$ emissions in kilotonnes of $CO_2$ per Petajoule of methane consumed is 49.7.

#### B3.1.2 Electricity

The electrical consumption is treated with respect to the consumption of GWh. A value of 0.88 kilotonnes of $CO_2$ per GWh of electrical energy consumed was used. This value was determined by TransAlta Utilities as being a representative value for 1989.

### B3.2 MEASURES

#### B3.2.1 Thermal Energy Conservation Measures

##### B3.2.1.1 Stripping Gas Reduction

The basis for determining the total number of glycol regenerators in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of sweet and sour gas producing wells were determined. From these numbers, an engineering estimate was used to determine what percentage of the sweet and what percentage of the sour gas wells have dehydration systems using glycol absorption, giving an industry wide total.

Engineering estimates were used to determine the percentage of actual applicable glycol regeneration units that could possibly reduce, recover or flare vented stripping gas.

The implementation level was based on newly designed glycol regeneration, being installed instead of old style glycol regenerators on all new installations in the future.

B3.2.1.2 Sulphur Incinerator Fuel Gas Reduction

The basis for determining the total number of sulphur incinerators in western Canada's oil and gas industry was from information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of sour gas plants were determined. Of the sour gas plants, large producers of sulphur were assumed to have sulphur incinerators, giving an industry wide total.

Engineering estimates were used to determine the percentage of actual applicable sulphur incineration units that would benefit from the installation of better combustion air control and reduced stack temperature.

The implementation was determined as a function of each measures ease of retrofit capabilities, capital cost, regulatory approval, payback period and savings of $CO_2$ per capital investment. Retrofitting existing sulphur incinerators with better combustion air control involves the installation of technical equipment and the need of competent personnel for proper operations. These factors will reduce the implementation even though the payback period is favourable. Reducing stack temperature is easily implemented, and favours a high implementation. The payback period is also favourable and again favours a high implementation.

If only one measure is to be applied to any one sulphur incinerator, the efficiency improvement is a direct function of the applied measure. Since better combustion air control and reducing the stack temperature are independent of each other, the

total efficiency improvement is the sum of the two individual energy efficiency improvements.

The overall penetration is a weighted average of the percent application implementation and energy efficiency.

B3.2.1.3 MEA to MDEA

The basis for determining the total number of MEA plants in western Canada's oil and gas industry was from information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia.

Engineering estimates were used to determine the percentage of applicable MEA plants that could realistically be converted to MDEA plants based on equipment type, adaptability and process needs.

The implementation was determined as a function of solvent replacement capabilities, capital cost per plant, shutdown periods, payback period, and the special process consideration that must be given, due to the uniqueness of each plant.

Efficiency improvement is in the trade off between fuel gas and electricity. With the substitution of MDEA for MEA, the fuel gas requirements are decreased and the electrical consumption is increased. The overall efficiency improvement is not applicable since we are dealing with two types of energy sources. For this reason, each must be dealt with separately.

The overall penetration is a function of the percent application and implementation. As the percent application and implementation are the same for all measures, the overall penetration is the product of the two.

B3.2.1.4 DEA to MDEA

The basis for determining the total number of DEA plants in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia.

Engineering estimates were used to determine the percentage of actual DEA plants that could realistically be converted to MDEA plants based on equipment type, adaptability and process needs.

The implementation was determined as a function of solvent replacement capabilities, capital cost per plant, shutdown periods, payback period, and the special process consideration that must be given due to the uniqueness of each plant.

Efficiency improvement is in the trade off between spent fuel gas and electricity. With the substitution of MDEA for DEA, the fuel gas requirements are decreased and the electrical consumption is increased. The overall efficiency improvement is not applicable since two types of energy sources are being dealt with. For this reason, each must be dealt with separately.

The overall penetration is a function of the percent application and implementation. As the percent application and implementation are the same for all measures, the overall penetration is the product of the two.

B3.2.1.5 Heater Efficiency Improvements

The basis for determining the total number of heaters in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of sweet and sour gas producing wells were determined. From these numbers, an engineering estimate was used to determine what percentage of the sweet and what percentage of the sour gas wells have heaters.

Engineering estimates were used to determine the percentage of heaters that would benefit from servicing and burner adjustments, the installation of a combustion air preheat, proper burner size, instrumentation for better burner control, damper controls, turbulators and burner replacement.

The implementation of individual measures was determined as a function of ease of retrofit capabilities, payout periods and dependency and interactions with other measures. The implementation of the measures; damper controls and replacement of burners was zero, due to the conflict with other measures that achieved the same efficiency improvements with more favourable payback periods. The overall efficiency improvement was based on the concept of diminishing returns with respect to the measures, servicing and burner adjustments, combustion air preheat, burner sizing, instrumentation and burner control.

The overall penetration was an engineering estimate based on the concept of diminishing returns.

B3.2.1.6 Added Field Heat Exchange

The basis for determining the total number of heater-treaters in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the number of oil wells, an estimate as to the number of oil batteries presently existing was determined. From this, the number of heater treaters was determined.

Engineering estimates were used to determine the percentage of actual applicable heater-treaters that could be used to recover heat from heater-treater exhaust gases.

The implementation was determined as a function of ease of retrofitting capabilities, use for recoverable energy and payback period.

B3.2.1.7 Waste Heat Recovery

The basis for determining the total number of gas engines 75 hp and up in western Canada's oil and gas industry was information obtained from major suppliers and manufacturers. This information consisted of the number of engines sold to industry in the past 30 years. Engineering estimates were used to determine how many of these engines sold were for new installations, how many were for replacement and how many were taken out of service.

Engineering estimates were used to determine the applicability of retrofitting exhaust recovery units on 75 hp and larger engines.

The implementation was estimated as a function of the measure's retrofit capabilities, use for recoverable energy and payback period.

B3.2.1.8 Gas Engines

The basis for determining the total number of gas engines 75 hp and up in western Canada's oil and gas industry was determined information obtained from major suppliers and manufacturers. This information consisted of the number of gas engines sold to industry in the past 10 years. Engineering estimates were used to determine how many of these gas engines sold were for new installations, how many were replacements, and how many were taken out of service. From these estimates, a total industry wide number was achieved.

Engineering estimates were used to determine applicability of retrofitting energy efficient engines on presently existing 75 hp and larger gas engines.

The implementation was determined as a function of the measures ease of retrofit capabilities and payback period.

B3.2.1.9 Optimize Pipeline Pressure

The basis for determining the total number of gathering systems in western Canada's oil and gas industry was from information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of processing plants was determined. Each processing plant was assumed to have an individual gathering system.

An engineering estimate was used to determine the applicability of changing initial pipeline design and looping of line in depleted fields.

There was no payback for the above noted measures and therefore no application and overall penetration.

B3.2.1.10 Hydrate Control System

The basis for determining the total number of line heaters in western Canada's oil and gas industry was determined by obtaining information from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of sweet and sour gas producing wells were determined. From these numbers, an engineering estimate was used to determine what percentage of the sweet and what percentage of the sour gas wells would have line heaters for hydrate control.

Engineering estimates were used to determine the percentage of line heaters that could be replaced by dehydrators, dry desiccants, glycol injection/recovery and methanol injection and be more energy efficient.

There was no payback for the above noted measures and therefore there is no application and overall penetration.

B3.2.1.11 Electrical Tracing vs. Steam Tracing

The basis for determining the total number of steam traced systems in western Canada's oil and gas processing industry was from information gathered from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of processing facilities was determined.

Engineering estimates were used to determine the percentage of steam, glycol systems that could be replaced with electrical tracing and be more energy efficient.

As there was no payback for the above noted substitution, there are no applications or overall efficiency figures.

B3.2.2 Electrical Energy Conservation Measures

B3.2.2.1 Compressors

The basis for determining the total number of compressors 75 hp and up in western Canada's oil and gas industry was information obtained from major suppliers and manufacturers. This information consisted of the number of compressors sold to industry in the past 30 years. Engineering estimates were used to determine how many of these compressors sold were for new installations, how many were replacements, and how many were taken out of service. From these estimates, a total industry wide number was achieved.

Engineering estimates were used to determine applicability of retrofitting energy efficient motors, variable speed drives and auto unloaders on 75 hp and up compressors in Western Canada's oil and gas industry.

The implementation was determined as a function of the measures ease of retrofit capabilities and low payback period relative to the different manufacturers.

Of the applicable compressors, each measure can be applied independently of the other. If only one measure is applied to any given compressor, the efficiency improvement is a direct function of that applied measure. If two measures were applied to a single compressor ( eg. energy efficient motors and variable speed drives), the total efficiency improvement of one would not effect the efficiency improvement of other, each is independent of the other. This is because measure each concentrates in a different area of the compressor operation and therefore allows the total efficiency improvement to be the sum of the two.

In the case of the two measures, auto unloaders and variable speed drives, being applied to a single compressor, the efficiency improvement of each measure is concentrated in the same area of the compressors operation, making the measures dependent on each other. If one measure is applied, the implementation of the second measure would only marginally, if at all, increase the total efficiency improvement. In this case, the prominent factors considered when choosing which dependent measure would be implemented, was the payback period of the measures. The efficiency improvement of the variable speed drives is better than that of the auto unloaders, resulting in a better payback period. Since both measures would not be implemented, and having the choice between the two, the variable drives would be implemented, reducing the implementation of auto unloaders.

B3.2.2.2 Pumps

The basis for determining total number of pumps in western Canada oil and gas industry was information obtained from major suppliers and manufacturers. This information consisted of the number of pumps sold to industry in the past 20 years. Engineering estimates were used to determine how many of these pumps sold were for new installations, how many were for replacements, and how many were taken out of service.

Engineering estimates were used to determine the percentage of actual applicable pumps that could be retrofitted with energy efficient motors and variable speed drives.

The implementation was determined as a function of each measures ease of retrofit capabilities and payback period. Retrofitting existing pumps with energy efficient motors and variable speed drives is easily implemented, and favours a high implementation. The payback period is also favourable and again favours a high implementation.

If only one measure is to be applied to any one pump, the efficiency improvement achieved is a direct function of the applied measure. Since energy efficient motors and variable speed drives are independent of each other, the total efficiency improvement is the sum of the two individual energy efficiency improvements.

The overall penetration is a function of percent application and implementation. As the percent application and implementation are the same for both measures and each measure can be applied to the same number of units, the overall penetration is the product of the percent application and implementation.

B3.2.2.3 Aerial Cooler

The basis for determining the total number of aerial coolers in western Canada's oil and gas industry was information obtained from major suppliers and manufacturers. This information consisted of the number of aerial coolers sold to industry in the past 20 years. Engineering estimates were used to determine how many of these aerial coolers that were sold in the past 20 years, were for new installations and replacements, and during this period, how many were taken out of service.

Engineering estimates were used to determine the percentage of actual applicable aerial coolers that could be retrofitted with energy efficient motors and variable speed drives.

The implementation was determined as a function of each measures ease of retrofit capabilities and payback period. Retrofitting existing aerial coolers with energy efficient motors and variable speed drives is easily implemented, and favours a high implementation. The payback period is also favourable and again favours a high implementation.

If only one measure is to be applied to any one aerial cooler, the efficiency improvement achieved is a direct function of the applied measure. Since energy efficient motors and variable speed drives are independent of each other, the total efficiency improvement is the sum of the two individual energy efficiency improvements.

The overall penetration is a function of percent application and implementation. Being that the percent application and implementation are the same for both measures and each measure can be applied to the same number of units, the overall penetration is the product of the percent application and implementation.

B3.2.2.4 Lighting (per plant)

The basis for determining the total number of large, medium and small plants in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. An engineering estimate was used to estimate the load of each plant due to exterior lighting.

Engineering estimates were used to determine the percentage of actual applicable plants that could be retrofitted with instrumentation and procedures to reduce exterior lighting loads.

The implementation was determined as a function of each measure's installation characteristics and economics. The payouts were low and therefore impeded the implementation.

The overall penetration is a function of the percent application and implementation. Being that the percent application and implementation are the same for all measures, the overall penetration is the product of the two.

B3.2.2.5 Pump Jacks

The basis for determining the total number of pump jacks in western Canada's oil and gas industry was information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From these boards the total number of producing oil wells was determined. An engineering estimate was used to determine the percentage of these wells that have pump jacks.

Engineering estimates were used to determine the percentage of actual applicable pump jacks that would benefit from applying a power factor correction capacitor.

The implementation was determined as a function of the power factor correction capacitors, ease of retrofit and payback period.

B3.2.2.6 Lighting (per fixture)

The basis for determining the total number of lighting fixtures in western Canada's oil and gas industry was by review of each individual plant in the industry and categorizing them into three classes (ie. small, medium and large). By estimating the load of each size of plant, and knowing the total number of plants in each class, an average load and overall industry wide load was achieved. Knowing the average load per fixture, the total number of fixtures was estimated.

Engineering estimates were used to determine the percentage of actual applicable lighting fixtures that could be replaced with HPS lamps (ie. incandescent and mercury vapour lamps with HPS lamps).

There is no payback period for the replacement of incandescent and mercury vapour lamps with HPS lamps, but due to the better lighting of the HPS lamps, the installation of these lamps is proceeding. The estimated implementation is based on present trends in industry today.

The overall penetration is a weighted average of the total energy consumption of each lamp, the number of lamps effected by each measures and the percent application and implementation.

B3.2.2.7 Pressure Reduction Energy Use

The basis for determining the total number of pressure throttling locations in western Canada's oil and gas industry was from information obtained from regulatory boards in Alberta, Manitoba, Saskatchewan and British Columbia. From the information provided, the number of processing plants was determined. Each processing plant was assumed to have a location at which throttling of inlet gas takes place. Added to these location was specific locations in which throttling takes place in sales gas piping, giving a total number of possible locations.

The implementation was determined as a function of the ease of retrofit capabilities and payback period.

## B3.3 ECONOMICS

### B3.3.1 Derivation of Payout Period Formula

#### B3.3.1.1 Before Income Tax and Royalty

Both revenue and operating costs are escalated and discounted at a common inflation factor (i = 0.05) and discount factor (d = 0.15). Annual net revenue (r) before tax is equal to the difference between annual gross revenue and annual operating costs.

The sum of the present worth of annual net revenue taken at mid year equals:

$$r\left(\frac{1+i}{1+d}\right)^{0.5} + r\left(\frac{1+i}{1+d}\right)^{1.5} + \ldots r\left(\frac{1+i}{1+d}\right)^{n-0.5}$$

This is a power series and the sum to year (n) equals:

$$r\left(\frac{1+i}{1+d}\right)^{0.5}\left(1-\left(\frac{1+i}{1+d}\right)^{n}\right) \;/\; \left(1-\left(\frac{1+i}{1+d}\right)\right)$$

The investment, (I) is made at time zero and the payout time is the year (n) that the present worth of the annual net revenues equals (I).

$$I = r\left(\frac{1+i}{1+d}\right)^{0.5}\left(1-\left(\frac{1+i}{1+d}\right)^{n}\right) \;/\; \left(1-\frac{1+i}{1+d}\right)$$

$$n = ln\left(1-\frac{I}{r}\left(\left(\frac{1+i}{1+d}\right)^{-0.5}-\left(\frac{1+i}{1+d}\right)^{0.5}\right)\right) / ln\left(\frac{1+i}{1+d}\right)$$

B3.3.1.2 After Income Tax and Royalty

To allow for the effect of income tax and royalties, the CPA Committee advised RTM to use 70% of the investment, 60% of the expenses and 45% of the revenues as outlined below. The same formula applies with these factors applied to I and r.

An after tax factor is simply a number which is used to convert a before tax cash outflow or inflow to an after tax equivalent. After tax factors are often used to perform or adjust economic analyses. Their strength lies in ease of use but it must be realized that these factors are only approximations and the many assumptions that go into their derivation may be critical to their applicability to an analysis.

After tax factors exist since the Income Tax of Canada allows corporate tax payers certain deductions associated with the costs of doing business and generating income. These deductions originate in the oil and gas business for such things as the cost of operations and spending for capital items. Therefore, a dollar of spending on a before tax basis may not equate to a dollar on an after tax basis.

The after tax factors supplied to RTM Engineering to perform their analysis were the following:

| | |
|---|---|
| Operating Cost | 0.60 |
| Capital | 0.70 |
| Revenue (After Tax) | 0.67 |
| Revenue (After Tax and Royalty) | 0.45 |

Their derivation is as follows (assuming a cash outflow as a negative item and a cash inflow as positive):

**Operating Costs:**

| | |
|---|---|
| Operating Expenditure (OE) | - OE |
| Tax Deduction<br>(.4384) (.75) + OE | +0.33 OE |
| Effect to Provincial Tax Rebate<br>(.15) (.25) | +0.04 OE |
| | -0.63 OE |

This was rounded down to -0.60. Note: There are several assumptions made here. First, a taxable position was assumed with an overall average E + P Tax Rate of 43.84 percent and a provincial tax rate of 15 percent (lowering either tax rate will increase the after tax factor). Secondly, no present valuing was performed in the derivation of any of these factors since PV'ing is done independently in the RTM analyses.

**Capital Costs:**

| | |
|---|---|
| Capital Expenditure | -1.0 CE |
| Tax Deduction<br>(.4384) (.72314) (.75) CE | +0.24 CE |
| Provincial Tax Rebate<br>(.15) (.25) (.72314) CE | +0.03 CE |
| | -0.73 CE |

This factor was rounded down to -0.70. The derivation assumes the same as the above regarding income tax rates, present valuing and gas plant equity. Additionally, the Capital Cost Allowance (CCA) for the Class 41 asset was performed at 25 percent declining balance with the half year rule applied. Only

five years of writeoffs were included since this was consistent with the payout period for the investments being analyzed. More periods will reduce the after factor, less periods will increase it.

**Revenue:**

| | | |
|---|---|---|
| Revenue Received | 1.0 Rev | |
| Income Tax Owing<br>-(0.4384) (0.75) Rev | -0.33 Rev | |
| | +0.67 Rev | (After Tax) |
| Royalty Rate<br>(Marginal on New Gas) | -0.27 Rev | |
| | 0.40 Rev | (After Tax* and After Royalty) |

The assumptions made here are the same as previous concerning tax rates and the treatment of PV. An argument might be made that it should not be the marginal royalty rate that should be used but rather an effective royalty rate (due to Gas Cost Allowance or GCA impact). A good effective rate to use would be somewhere in the 0.18 to 0.20 range which would yield and after tax and after royalty factor of (0.47 to 0.49 Rev). Thus, it was decided to split the difference and use an after tax and after royalty factor of 0.45.

* This value is not used, but rather 0.45 as clarified in the narrative.

B3.3.2 General Economics

B3.3.2.1 Fuel Gas Costs

In much of the gas production and processing industry, fuel gas is usually valued at zero $/GJ. For there to be any economics involved, with respect to $CO_2$ savings, there must be a value placed on fuel gas. With reference to the "Alberta Department of Energy's $CO_2$ Reduction Study", a value of $1.65/GJ of fuel consumed was used as a base case. In order to cover a range of fuel cost values, a sensitivity was performed using fuel values of $1.30/GJ and $2.00/GJ.

B3.3.2.2 Electricity Costs

The electrical energy charge for the first 400 kWh/month kW of demand is 1.75 cents/kWh, and 0.95 cents/kWh for all succeeding energy consumption. Since all energy conservation reduction will be credited towards decreasing energy consumption over 400 kWh/month/kW, the latter of the two charges, 0.95 cents/kWh, was used for electrical energy conserved. The utility companies also charge based upon the peak demand of electrical energy used in a given time period. Estimations of electrical energy consumption reductions can generally be determined based on assumptions of efficiency improvements, but the peak demand levels during a given time period incorporates unexpected and unforeseen variables that are not easily predicted. For this reason, an overall corrected electrical energy charge was used based on the assumption that the demand load would change accordingly with consumption. The corrected electrical energy charge used was 3.54¢/kWh.

B3.3.3 Economic Summary Tables

List of Tables

| Table Number | Table Name |
|---|---|
| 3.3.3.1 | Thermal Economic Sensitivity |
| 3.3.3.2 | Electrical Economic Summary |

# TABLE B3.3.3.1
# THERMAL ECONOMIC SENSITIVITY

| No. | Measure | Energy Type | Gas Value @ 1.30 $/GJ | | Gas Value @ 1.65 $/GJ | | Gas Value @ 2.00 $/GJ | |
|---|---|---|---|---|---|---|---|---|
| | | | Before Tax and Royalty Pay Back Period (yrs) | After Tax and Royalty Pay Back Period (yrs) | Before Tax and Royalty Pay Back Period (yrs) | After Tax and Royalty Pay Back Period (yrs) | Before Tax and Royalty Pay Back Period (yrs) | After Tax and Royalty Pay Back Period (yrs) |
| 1 | Stripping Gas Reduction | Fuel | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | Sulfur Inc. Fuel Gas Red'n | Fuel | 0.44 | 0.78 | 0.34 | 0.57 | 0.27 | 0.46 |
| | - Better Comb. Air Control | Fuel | 0.69 | 1.16 | 0.53 | 0.89 | 0.43 | 0.72 |
| | - Reduced Stack Temp. | Fuel | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | MEA to MDEA | F/E | 0.42 | 0.61 | 0.34 | 0.50 | 0.29 | 0.44 |
| | - Fuel gas requirements | Fuel | N/A | N/A | N/A | N/A | N/A | N/A |
| | - Electrical requirements | Elec | N/A | N/A | N/A | N/A | N/A | N/A |
| 4 | DEA to MDEA | F/E | 0.53 | 0.74 | 0.41 | 0.60 | 0.36 | 0.53 |
| | - Fuel gas requirements | Fuel | N/A | N/A | N/A | N/A | N/A | N/A |
| | - Electrical requirements | Elec | N/A | N/A | N/A | N/A | N/A | N/A |
| 5 | Heater Eff. Improv. | Fuel | 1.09 | 2.46 | 0.73 | 1.46 | 0.55 | 1.04 |
| | - Servicing and Burner Adjust | Fuel | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | - Combustion Air Preheat | Fuel | 14.39 | N.P. | 9.41 | N.P. | 7.07 | 16.10 |
| | - Burner Sizing | Fuel | 0.94 | 1.57 | 0.74 | 1.22 | 0.60 | 0.99 |
| | - Instr'n and Burner Control | Fuel | N.P. | N.P. | 21.01 | N.P. | 10.09 | N.P. |
| 6 | Added Field Heat Exchange | | | | | | | |
| | - Fld htr-treater exh't recovery | Fuel | 2.51 | 4.89 | 1.63 | 3.37 | 1.44 | 2.57 |
| 7 | Waste Heat Recovery | | | | | | | |
| | - Eng. exh't exch. for bldg ht | Fuel | N.P. | N.P. | 18.98 | N.P. | 9.60 | N.P. |
| 8 | Gas Eng. Fuel Eff Improv (75 hp+) | | | | | | | |
| | - Retrofit system on exist'g units | Fuel | N.P. | N.P. | 33.60 | N.P. | 16.96 | N.P. |

* N.P. = No Pay Back

** Measures which have no pay back period are not included in this summary but may be seen in Table B2.2.3.

# TABLE B3.3.3.2
# ELECTRICAL ECONOMIC SUMMARY

| No. | Measure | Energy Type | Electricity Value @ 0.0354 $/GWh: Before Tax and Royalty Pay Back Period (yrs) | Electricity Value @ 0.0354 $/GWh: After Tax and Royalty Pay Back Period (yrs) |
|---|---|---|---|---|
| 1 | Compressors (75 hp +) | Elec | 0.21 | 0.33 |
| | - Energy Efficient Motors | Elec | 0.26 | 0.41 |
| | - Variable Speed Drives | Elec | 0.21 | 0.32 |
| 2 | Pump Systems | Elec | 1.20 | 1.93 |
| | - Energy Efficient Motors | Elec | 0.73 | 1.16 |
| | - Variable Speed Drives | Elec | 1.29 | 2.07 |
| 3 | Aerial Coolers | Elec | 1.52 | 2.47 |
| | - Energy Efficient Motors | Elec | 3.20 | 5.48 |
| | - Variable Speed Drives | Elec | 1.41 | 2.28 |
| 4 | Lighting (per plant) | Elec | 4.79 | 8.75 |
| | - Red. Ext. Ltg levels in Lrg Plts. | Elec | 4.77 | 8.72 |
| | - Red. Ext. Ltg levels in Med Plts. | Elec | 4.97 | 9.18 |
| | - Red. Ext. Ltg levels in Sml Plts. | Elec | 5.03 | 9.30 |
| 5 | Pump Jacks | | | |
| | - Power Factor Correction | Elec | 0.38 | 0.60 |
| 6 | Lighting (per fixture) | Elec | N.P. | N.P. |
| | - Repl. Incond. with a HPS Lamp | Elec | N.P. | N.P. |
| | - Repl. Merc. Vap. with a HPS lamp | Elec | N.P. | N.P. |

* N.P. = No Pay Back

** Measures which have no pay back period are not included in this summary but may be seen in Table B2.2.4.

## B4.0 DATA SHEETS

B4.1 LIST OF DATA SHEETS INCLUDE:

| Sheet Number | Title |
|---|---|
| T1 | Stripping Gas Reduction |
| T2 | Sulphur Incineration Fuel Gas Reduction |
| T3 | MEA to MDEA |
| T4 | DEA to MDEA |
| T5 | Heater Efficiency Improvement |
| T6 | Process (Field) Heat Exchange |
| T7 | Waste Heat Recovery |
| T8 | Gas Driver Fuel Efficiency Improvement |
| T9 | Optimize Pipeline Pressure |
| T10 | Hydrate Control Systems |
| T11 | Electrical Tracing in Lieu of Steam/Hot Glycol Tracing |
| E1 | Compressors |
| E2 | Pump Systems |
| E3 | Aerial Coolers |
| E4 | Lighting Improvements (per plant) |
| E5 | Pump Jacks |
| E6 | Lighting Improvements (per fixture) |
| E7 | Pressure Reduction Energy Use |

# DATA SHEET
## Overall Summary
## T1 - Stripping Gas Reduction

### APPLICATION DESCRIPTION

*A large portion of gas which is flared may be potentially reduced by implementation of higher regeneration boiler temperatures, using tri-ethylene glycol (TEG) inplace of di-ethylene glycol (DEG) or tetra-ethylene glycol in place of TEG, creating a partial vaccum on the reboiler with a small blower or compressor or finally increasing the circulation rate.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

T1a *Glycol Regenerator Stripping Gas - Plant regenerators should recover the gas and field units should not be allowed to vent stripping gas. Please see write-up for details. Plant dehydrators using stripping gas can easily use vent gas in flare system. Field units often cannot. Estimate there are 70 field units. The dollar savings would cover a change to a heavier type of glycol or higher regeneration temperatures.*

### SUMMARY

**Industry Wide Facilities Characteristics**

| | | |
|---|---|---|
| **Total Energy Consumption:** | 0.70 | (PJ/yr) : GWh |
| **Total # of Units:** | 70 | |

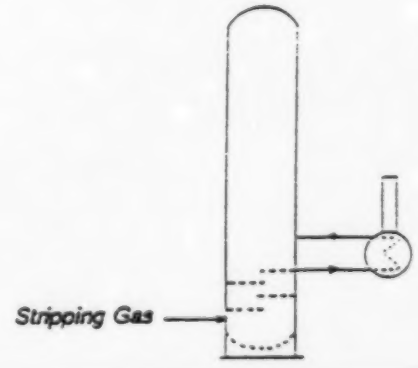
**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | 40.00 | % |
| **Efficiency Improvement:** | 100.00 | % |
| **Energy Conserved:** | 0.280 | (PJ/yr) : GWh |
| **Differential Capital Cost** | 0.00 | $ |
| **Gross Economic Savings:** | 0.46 x 10^6 | $/yr |
| **Differential Operating Cost:** | 0.00 | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | 0 | $/kt/yr |
| **CO2 Conserved:** | 13.94 | kt/yr |
| **Before Tax & Royalty Pay Back:** | 0.00 | yrs |

### DIAGRAM/FIGURE

*From 1 to 5 scf of stripping gas is introduced into the regenerator reboiler to help strip the water from the glycol. It is best done using a number of trays below the reboiler, however, very few field glycol regenerators are built this way.*




### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T1 - Stripping Gas Reduction

| OPPORTUNITY T1a: Stripping Gas Reduction | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | | % |
| Implementation: | 40.00 | % | Implementation: | | % |
| Efficiency Improvement: | 100.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 0.28 | (PJ/yr) : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 0.46 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 13.94 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 0.00 | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET

## Overall Summary

## T2 - Sulphur Incineration Fuel Gas Reduction

### APPLICATION DESCRIPTION

*Sulphur incineration is used extensively in sour gas processing to break down sulphur compounds, prevent odour (traces of H2S) and disperse incinerated acid gas byproducts prior to entering the atmosphere.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*T2a Better combustion air control - adjust combustion air to stoichiometric ratios.*

*T2b Reduce stack temperature - by reducing fuel gas flow. (ie. requires government approval and plume survey)*

### SUMMARY

**Industry Wide Facilities Characteristics**

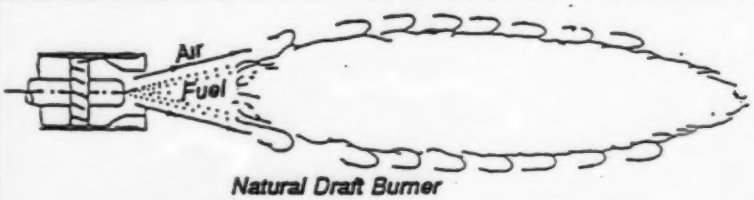
| | | |
|---|---|---|
| **Total Energy Consumption:** | *28.06* | (PJ/yr) : GWh |
| **Total # of Units:** | *56* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

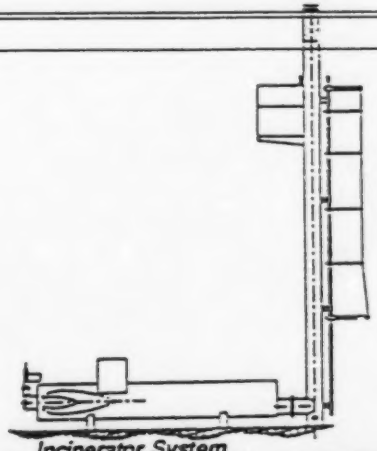
| | | |
|---|---|---|
| **Overall Penetration:** | *58.44* | % |
| **Efficiency Improvement:** | *38.70* | % |
| **Energy Conserved:** | *6.35* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *2.80 x 10^6* | $ |
| **Gross Economic Savings:** | *10.49 x 10^6* | $/yr |
| **Differential Operating Cost:** | *1.09 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *8865* | $/kt/yr |
| **CO2 Conserved:** | *315.39* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0.34* | yrs |

### DIAGRAM/FIGURE




*Natural Draft Burner*

*Specialized Burner*



*Incinerator System*

### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T2 - Sulphur Incineration Fuel Gas Reduction

| OPPORTUNITY T2a: Better Combust'n Air Control | | | OPPORTUNITY T2b: Reduce Stack Temperature | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | 80.00 | % |
| Implementation: | 50.00 | % | Implementation: | 90.00 | % |
| Efficiency Improvement: | 23.70 | % | Efficiency Improvement: | 15.00 | % |
| Energy Conserved: | 3.32 | (PJ/yr) : GWh | Energy Conserved: | 3.03 | (PJ/yr) : GWh |
| Differential Capital Cost: | 2.80 x 10^6 | $ | Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 5.49 x 10^6 | $/yr | Gross Economic Savings: | 5.00 x10^6 | $/yr |
| Differential Operating Cost: | 0.28 | $/yr | Differential Operating Cost: | 0.81 x 10^6 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 16944 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 165.25 | kt/yr | CO2 Conserved: | 150.61 | kt/yr |
| Before Tax & Royalty Pay Back: | 0.53 | yrs | Before Tax & Royalty Pay Back: | 0.00 | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T3 - MEA to MDEA

### APPLICATION DESCRIPTION

*New MDEA based solvents are now available for acid gas processing in the oil and gas industry. These solvents possess a higher selectivity and require less regeneration energy than the presently existing MEA.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*T3a Fuel gas requirements*

*T3b Electrical requirements*

### SUMMARY

**Industry Wide Facilities Characteristics**

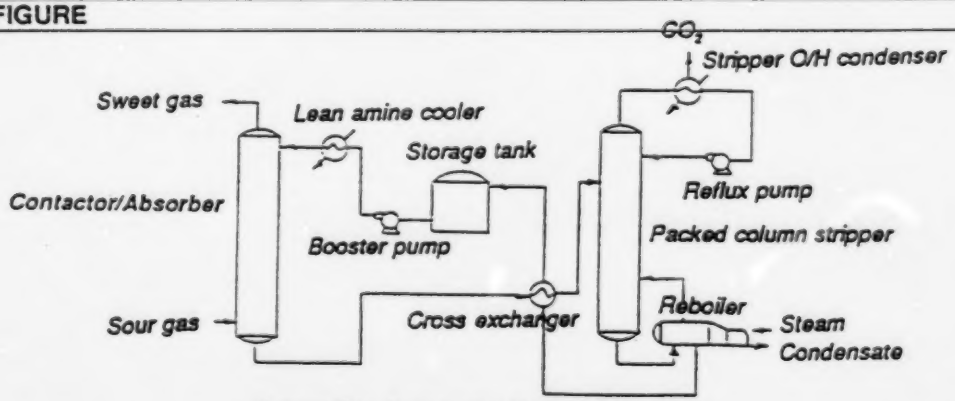
| | | |
|---|---|---|
| **Total Energy Consumption:** | *49.88* | (PJ/yr) : GWh |
| **Total # of Units:** | *40* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *27.00* | % |
| **Efficiency Improvement:** | *N/A* | % |
| **Energy Conserved:** | *N/A* | PJ/yr : GWh |
| **Differential Capital Cost** | *4.97 x 10^6* | $ |
| **Gross Economic Savings:** | *9.55 x 10^6* | $/yr |
| **Differential Operating Cost:** | *-4.32 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *16944* | $/kt/yr |
| **CO2 Conserved:** | *293.20* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0.34* | yrs |

### DIAGRAM/FIGURE




*Natural Gas Sweetening Process Flow Sheet*

### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T3 - MEA to MDEA

| OPPORTUNITY T3a: Fuel gas requirements | | | OPPORTUNITY T3b: Electrical requirements | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | 90.00 | % |
| Implementation: | 30.00 | % | Implementation: | 30.00 | % |
| Efficiency Improvement: | 47.80 | % | Efficiency Improvement: | 0.00 | % |
| Energy Conserved: | 6.44 | (PJ/yr) : GWh | Energy Conserved: | -30.39 | PJ/yr : (GWh) |
| Differential Capital Cost: | 4.97 x 10^6 | $ | Differential Capital Cost: | N/A | $ |
| Gross Economic Savings: | 10.62 x 10^6 | $/yr | Gross Economic Savings: | -1.08 x 10^6 | $/yr |
| Differential Operating Cost: | -4.32 x 10^6 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | N/A | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | N/A | $/kt/yr |
| CO2 Conserved: | N/A | kt/yr | CO2 Conserved: | N/A | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T4 - DEA to MDEA

**APPLICATION DESCRIPTION**

*New MDEA based solvents are now available for acid gas processing in the oil and gas industry. These solvents possess a higher selectivity and require less regeneration energy than the presently existing DEA.*

**ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES**

**Opportunity**

*T4a Fuel gas requirements*

*T4b Electrical requirements*

**SUMMARY**

**Industry Wide Facilities Characteristics**

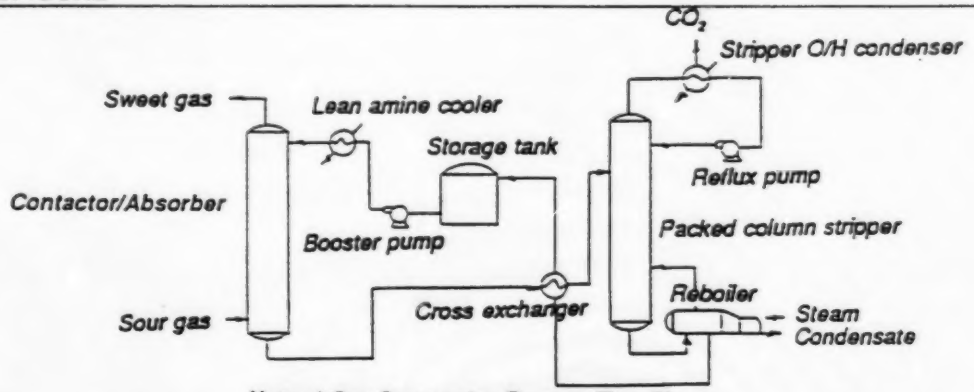
| | | |
|---|---|---|
| **Total Energy Consumption:** | *93.58* | (PJ/yr) : GWh |
| **Total # of Units:** | *84* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *27.00* | % |
| **Efficiency Improvement:** | *N/A* | % |
| **Energy Conserved:** | *N/A* | PJ/yr : GWh |
| **Differential Capital Cost** | *10.43 x 10^6* | $ |
| **Gross Economic Savings:** | *14.13 x 10^6* | $/yr |
| **Differential Operating Cost:** | *-9.07 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *23582* | $/kt/yr |
| **CO2 Conserved:** | *442.40* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0.41* | yrs |

**DIAGRAM/FIGURE**




*Natural Gas Sweetening Process Flow Sheet*

**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T4 - DEA to MDEA

| OPPORTUNITY T4a: Fuel gas requirements | | | OPPORTUNITY T4b: Electrical requirements | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | 90.00 | % |
| Implementation: | 30.00 | % | Implementation: | 30.00 | % |
| Efficiency Improvement: | 41.60 | % | Efficiency Improvement: | 0.00 | % |
| Energy Conserved: | 10.51 | (PJ/yr) : GWh | Energy Conserved: | -90.88 | PJ/yr : (GWh) |
| Differential Capital Cost: | 10.43 x 10^6 | $ | Differential Capital Cost: | N/A | $ |
| Gross Economic Savings: | 17.34 x 10^6 | $/yr | Gross Economic Savings: | -3.22 x 10^6 | $/yr |
| Differential Operating Cost: | -9.07 x 10^6 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | N/A | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | N/A | $/kt/yr |
| CO2 Conserved: | N/A | kt/yr | CO2 Conserved: | N/A | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T5 - Heater Efficiency Improvement

**APPLICATION DESCRIPTION**

*Gas fired heaters are used extensively throughout the oil and gas industry. Typical examples are indirect line heaters, process salt bath heaters, dehydrator regenerators, free water knockout heater treaters, and steam boilers in heavy oil production.*

**ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES**

**Opportunity**

- T5a *Servicing and Burner Adjustments*
- T5b *Combustion Air Preheat - Heat combustion air to limit effects of stack draft cooling due to burner cycling.*
- T5c *Burner Sizing - change burners to accommodate depleting field flowrates and proper sizing of existing burners.*
- T5d *Instrumentation and Burner Control - Implement instrumentation to adjust primary and secondary fuel gases and burner turndown.*
- T5e *Combustion Air and Flue Gas Damper Controls - Optimize flame quality/ stack draft by installing dampers to adjust the volume of combustion air control.*
- T5f *Turbulators - Improves air mixing thus enhancing heat transfer.*
- T5g *Burner Replacement*

**SUMMARY**

**Industry Wide Facilities Characteristics**

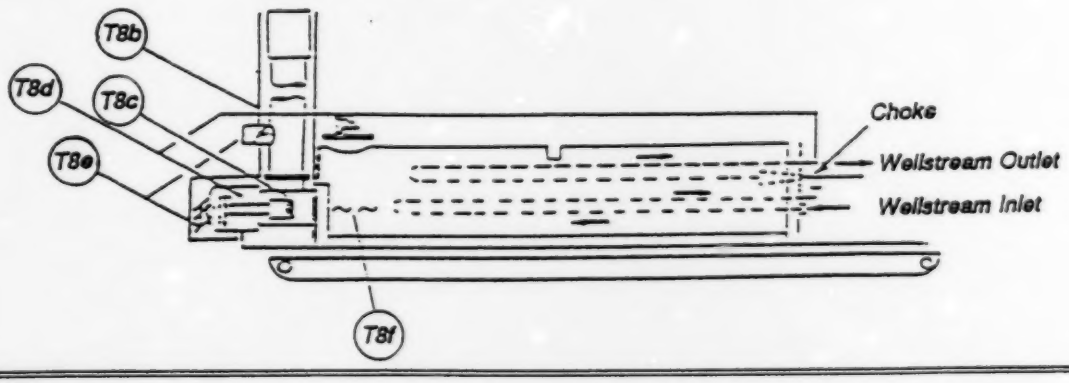
| | | |
|---|---|---|
| **Total Energy Consumption:** | *7.07* | (PJ/yr) : GWh |
| **Total # of Units:** | *11526* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *50.00* | % |
| **Efficiency Improvement:** | *30.00* | % |
| **Energy Conserved:** | *1.06* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *0.86 x 10^6* | $ |
| **Gross Economic Savings:** | *1.75 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.58 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *16393* | $/kt/yr |
| **CO2 Conserved:** | *52.73* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0.73* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual unit information, see Table B4.1-1.*
* *Field heaters are distinguished from inplant heaters by their poor maintainance due to their remote location and less technically knowledgeal relative to a large plant. Line heaters, small gas dehydrators, and small oilbattery treaters fall into this category. Indirect line heaters are use heat a gas stream to prevent flowline freeze-ups due to hydrate formation.*

# DATA SHEET

## Industrial Opportunity Summary

## T5 - Heater Efficiency Improvement

### OPPORTUNITY T5a: Servicing and burner adjust

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 65.00 | % |
| Efficiency Improvement: | 20.00 | % |
| Energy Conserved: | 0.92 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 1.52 x 10^6 | $/yr |
| Differential Operating Cost: | 0.75 x 10^6 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 45.7 | kt/yr |
| Before Tax & Royalty Pay Back: | 0.00 | yrs |

### OPPORTUNITY T5b: Combustion Air Preheat

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 20.00 | % |
| Efficiency Improvement: | 15.00 | % |
| Energy Conserved: | 0.21 | (PJ/yr) : GWh |
| Differential Capital Cost: | 2.31 x 10^6 | $ |
| Gross Economic Savings: | 0.35 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 218579 | $/kt/yr |
| CO2 Conserved: | 10.55 | kt/yr |
| Before Tax & Royalty Pay Back: | 9.41 | yrs |

### OPPORTUNITY T5c: Burner Sizing

| | | |
|---|---|---|
| Application: | 90.00 | % |
| Implementation: | 40.00 | % |
| Efficiency Improvement: | 20.00 | % |
| Energy Conserved: | 0.51 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.62 x 10^6 | $ |
| Gross Economic Savings: | 0.84 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 24590 | $/kt/yr |
| CO2 Conserved: | 25.31 | kt/yr |
| Before Tax & Royalty Pay Back: | 0.74 | yrs |

### OPPORTUNITY T5d: Instr'n and Burner Control

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 10.00 | % |
| Efficiency Improvement: | 20.00 | % |
| Energy Conserved: | 0.14 | (PJ/yr) : GWh |
| Differential Capital Cost: | 1.15 x 10^6 | $ |
| Gross Economic Savings: | 0.23 x 10^6 | $/yr |
| Differential Operating Cost: | 0.12 x 10^6 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 163934 | $/kt/yr |
| CO2 Conserved: | 7.03 | kt/yr |
| Before Tax & Royalty Pay Back: | 21.01 | yrs |

# DATA SHEET

## Industrial Opportunity Summary

## T5 - Heater Efficiency Improvement

### OPPORTUNITY T5e: Damper Controls

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 0.00 | % |
| Efficiency Improvement: | 10.00 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs |

### OPPORTUNITY T5f: Turbulators

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 0.00 | % |
| Efficiency Improvement: | 5.00 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs |

### OPPORTUNITY T5g: Burner Replacement

| | | |
|---|---|---|
| Application: | 100.00 | % |
| Implementation: | 0.00 | % |
| Efficiency Improvement: | 20.00 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs |

### OPPORTUNITY

| | | |
|---|---|---|
| Application: | | % |
| Implementation: | | % |
| Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T6 - Process (Field) Heat Exchange

### APPLICATION DESCRIPTION

*Heat exchange is utilized throughout the oil and gas industry. The principal application for added field heat exchange is on heater treater services. Installing a heat exchanger upstream of a heater treater greatly reduces the heat load on the treater.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

| | Opportunity |
|---|---|
| T6a | *Added field heat exchange - preheat wellhead oil with the oil and water recovered from the heater treater.* |

### SUMMARY

**Industry Wide Facilities Characteristics**

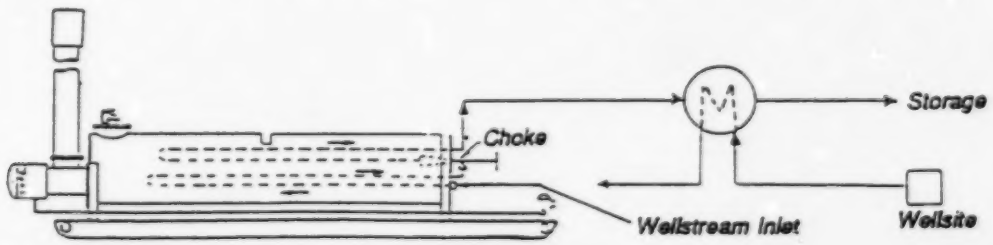
| | | |
|---|---|---|
| **Total Energy Consumption:** | *65.50* | (PJ/yr) : GWh |
| **Total # of Units:** | *6727* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *33.75* | % |
| **Efficiency Improvement:** | *25.00* | % |
| **Energy Conserved:** | *5.53* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *13.62 x 10^6* | $ |
| **Gross Economic Savings:** | *9.12 x 10^6* | $/yr |
| **Differential Operating Cost:** | *1.36 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *49595* | $/kt/yr |
| **CO2 Conserved:** | *274.67* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *1.83* | yrs |

### DIAGRAM/FIGURE




### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T6 - Added Field Heat Exchange

| OPPORTUNITY T6a: Added Field Heat Exchange | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 75.00 | % | Application: | | % |
| Implementation: | 45.00 | % | Implementation: | | % |
| Efficiency Improvement: | 25.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 5.53 | (PJ/yr) : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 13.62 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 9.12 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 1.36 x 10^6 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 49595 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 274.67 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 1.83 | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T7 - Waste Heat Recovery

**APPLICATION DESCRIPTION**

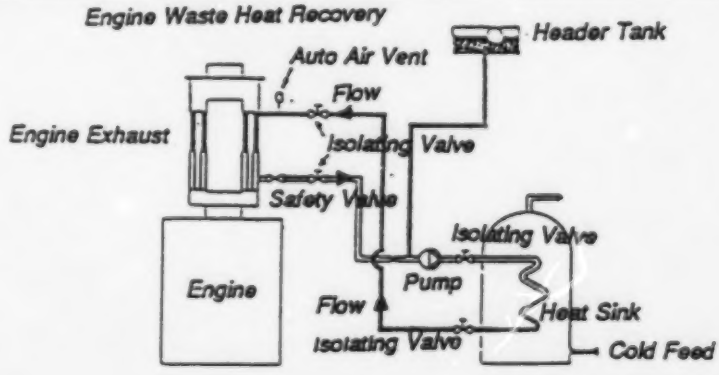
*Waste heat recovery in oil and gas processing may be implemented for plant utilities. A specific application would be recovering the heat from engine exhaust via a heat exchanger to heat glycol for use in heating buildings.*

| ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES | SUMMARY |
|---|---|
| **Opportunity** | **Industry Wide Facilities Characteristics** |
| *T7a Engine exhaust to heat glycol for building heat for 7 months per year.* | **Total Energy Consumption:** *36.21* (PJ/yr) : GWh<br>**Total # of Units:** *4345* |

**Energy/CO2 Conservation Opportunity Measures Economics**
***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *4.5* | % |
| **Efficiency Improvement:** | *15.00* | % |
| **Energy Conserved:** | *0.24* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *1.96 x 10^6* | $ |
| **Gross Economic Savings:** | *0.40 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.20 x 10^6* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *160963* | $/kt/yr |
| **CO2 Conserved:** | *12.15* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *18.98* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

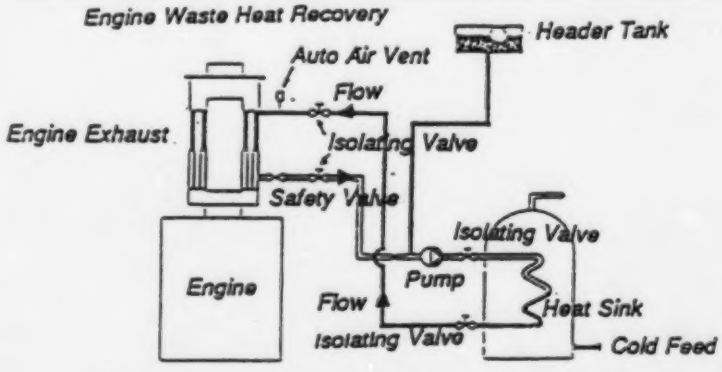
# DATA SHEET
## Overall Summary
## T7 - Waste Heat Recovery

**APPLICATION DESCRIPTION**

*Waste heat recovery in oil and gas processing may be implemented for plant utilities. A specific application would be recovering the heat from engine exhaust via a heat exchanger to heat glycol for use in heating buildings.*

| ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES | SUMMARY |
|---|---|
| **Opportunity** | **Industry Wide Facilities Characteristics** |
| *T7a Engine exhaust to heat glycol for building heat for 7 months per year.* | **Total Energy Consumption:** *36.21* (PJ/yr) : GWh<br>**Total # of Units:** *4345* |
| | **Energy/CO2 Conservation Opportunity Measures Economics**<br>***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)*** |
| | **Overall Penetration:** *4.5* %<br>**Efficiency Improvement:** *15.00* %<br>**Energy Conserved:** *0.24* (PJ/yr) : GWh<br>**Differential Capital Cost** *1.96 x 10^6* $<br>**Gross Economic Savings:** *0.40 x 10^6* $/yr<br>**Differential Operating Cost:** *0.20 x 10^6* $/yr<br>**Cap. Cost/kt CO2 Reduct./yr:** *160963* $/kt/yr<br>**CO2 Conserved:** *12.15* kt/yr<br>**Before Tax & Royalty Pay Back:** *18.98* yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T7 - Waste Heat Recovery

| OPPORTUNITY T7a: Engine Exhaust for Utilities | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | | % |
| Implementation: | 5.00 | % | Implementation: | | % |
| Efficiency Improvement: | 15.60 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 0.24 | (PJ/yr) : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 1.96 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 0.40 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.20 x 10^6 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 160963 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 12.15 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 18.98 | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET

## Overall Summary

## T8 - Gas Driver Fuel Efficiency Improvement

**APPLICATION DESCRIPTION**

*Reciprocating gas engines are used in numerous types of equipment such as compressor and pump jack drives, pumps, generators, and blowers. Gas turbines are used for large compressor drives.*

| ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES | |
|---|---|
| **Opportunity** | |
| T8a | *Reciprocating retrofit packages on existing units with lean burn, high efficiency combustion systems.* |

**SUMMARY**

**Industry Wide Facilities Characteristics**

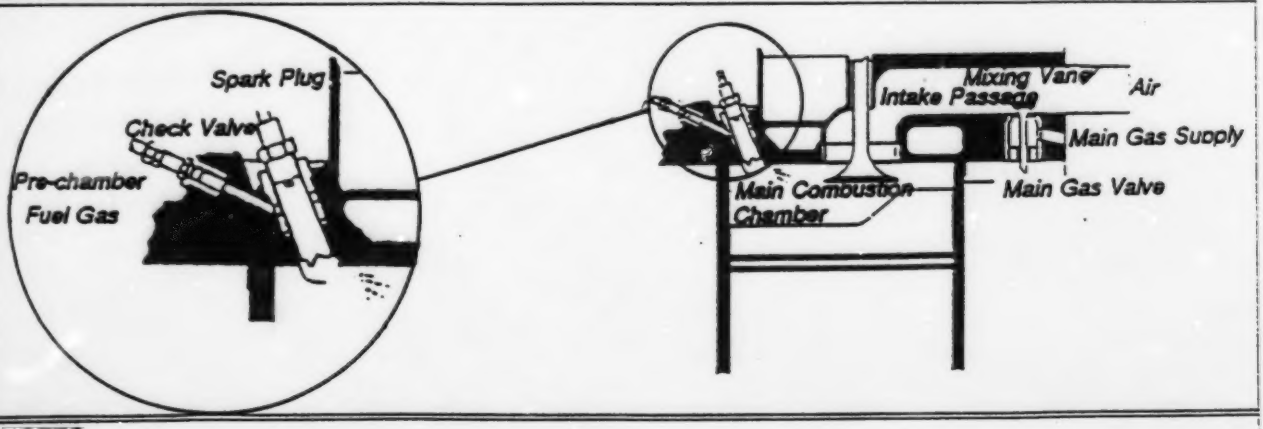
| | | |
|---|---|---|
| **Total Energy Consumption:** | *72.42* | (PJ/yr) : GWh |
| **Total # of Units:** | *4345* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *9.00* | % |
| **Efficiency Improvement:** | *10.00* | % |
| **Energy Conserved:** | *0.65* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *11.73 x 10^6* | $ |
| **Gross Economic Savings:** | *1.08 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *362171* | $/kt/yr |
| **CO2 Conserved:** | *32.39* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *33.60* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T8 - Gas Driver Fuel Efficiency Improvement

| OPPORTUNITY T8a: Reciprocating Retrofit Pkg | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | | % |
| Implementation: | 10.00 | % | Implementation: | | % |
| Efficiency Improvement: | 10.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 0.65 | (PJ/yr) : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 11.73 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 1.08 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 362171 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 32.39 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 33.60 | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T9 - Optimize Pipeline Pressures

**APPLICATION DESCRIPTION**

*Gas pipeline gathering systems and delivery lines are generally designed with larger than optimum pressure loss gradients in order to save on installed pipeline costs. When plant inlet compression is required, friction pressure drops add to the overall horsepower requirements. Also, declining pressures in some fields result in high gas velocities and consequently high line losses. Oil pipeline systems are generally operated at the minimum possible pressures to minimize initial capital investment. High friction pressure drops are sometimes encountered.*

| ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES | |
|---|---|
| OpportuOpportunity | |
| T9a | *Initial Pipeline Design - Compare costs associated with increased line size and reduced compressor drive size.* |
| T9b | *Looping Lines - As field pressures decline increasing pipeline velocities result in increasing compressor power demands. Compare capital and operating costs of looping lines with increased compressor drive size necessary to overcome increased line losses.* |

**SUMMARY**

**Industry Wide Facilities Characteristics**

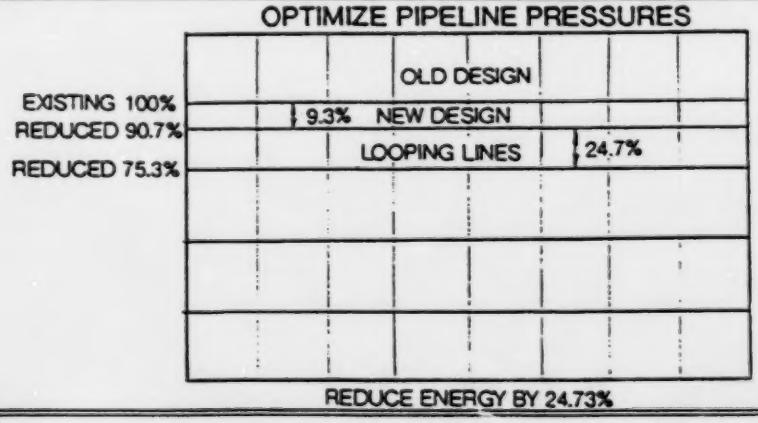
| | | |
|---|---|---|
| **Total Energy Consumption:** | *N/A* | (PJ/yr) : GWh |
| **Total # of Units:** | *550* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *0.00* | % |
| **Efficiency Improvement:** | *N/A* | % |
| **Energy Conserved:** | *0.00* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *0.00* | $ |
| **Gross Economic Savings:** | *0.00* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *0* | $/kt/yr |
| **CO2 Conserved:** | *0.00* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *N.P.* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T9 - Optimize Pipeline Pressures

| OPPORTUNITY T9a: Initial Design | | | OPPORTUNITY T9b: Looping Lines | | |
|---|---|---|---|---|---|
| Application: | 20.00 | % | Application: | 90.00 | % |
| Implementation: | 0.00 | % | Implementation: | 0.00 | % |
| Efficiency Improvement: | 9.30 | % | Efficiency Improvement: | 24.70 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh | Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr | Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr | CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## T10 - Hydrate Control Systems

### APPLICATION DESCRIPTION

*Hydrate control is used extensively in gas transmission. Hydrates occur where the gas stream encounters a pressure drop sufficient to decrease the gas temperature to that at which hydrates will form. Hydrate control is accomplished by:*

1) *heating the gas stream above the hydrate formation temperature,*
2) *lowering the hydrate formation temperature by gas dehydration or by methanol or glycol injection.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*T10a Glycol Dehydrators - install dehydrator in field and circulate nch glycol to plant for regeneration.*

*T10b Dry Dessicant Dehydrators - install 2 mole sieve dehydrators in field downstream of existing separator complete with dessicant regeneration system. Fuel gas for heater will be supplied by the plant via existing heater fuel gas line.*

*T10c Glycol Injection/Recovery - install a storage tank and drip pot in the field. The glycol is recovered at the plant, regenerated, then pumped back to the field via existing line heater fuel gas line.*

*T10d Methanol Injection/No Recovery - methanol is trucked to field storage tank.*

### SUMMARY

**Industry Wide Facilities Characteristics**

| | | |
|---|---|---|
| **Total Energy Consumption:** | *3.05* | (PJ/yr) : GWh |
| **Total # of Units:** | *4799* | |

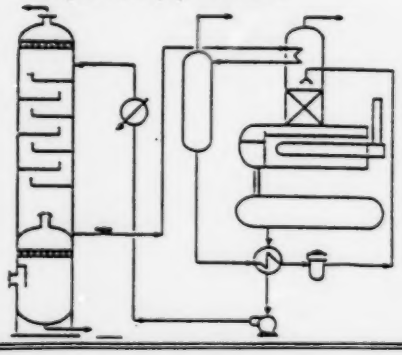
**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

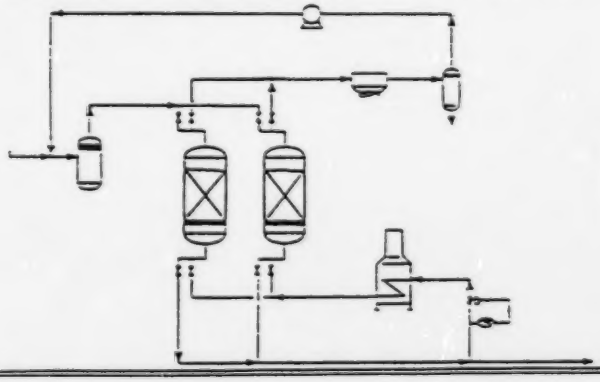
| | | |
|---|---|---|
| **Overall Penetration:** | *0.00* | % |
| **Efficiency Improvement:** | *100.00* | % |
| **Energy Conserved:** | *0.00* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *0.00* | $ |
| **Gross Economic Savings:** | *0.00* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *0.00* | $/kt/yr |
| **CO2 Conserved:** | *0.00* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *N.P.* | yrs |

### DIAGRAM/FIGURE

*Example Process Flow Diagram for Glycol Dehydration Unit*



*Example Solid Desiccant Dehydrator Twin Tower Systems*



### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T10 - Hydrate Control Systems

| OPPORTUNITY T10a: Glycol Dehydrators | | | OPPORTUNITY T10b: Dry Dessicant Dehydrators | | |
|---|---|---|---|---|---|
| Application: | 20.00 | % | Application: | 80.00 | % |
| Implementation: | 0.00 | % | Implementation: | 0.00 | % |
| Efficiency Improvement: | 88.00 | % | Efficiency Improvement: | 70.8 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh | Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr | Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr | CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

| OPPORTUNITY T10c: Glycol Injection/Recovery | | | OPPORTUNITY T10c: Methanol Inj'n/No Recovery | | |
|---|---|---|---|---|---|
| Application: | 85.00 | % | Application: | 90.00 | % |
| Implementation: | 0.00 | % | Implementation: | 0.00 | % |
| Efficiency Improvement: | 88.4 | % | Efficiency Improvement: | 100.00 | % |
| Energy Conserved: | 0.00 | (PJ/yr) : GWh | Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr | Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr | CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

# DATA SHEET

## Overall Summary

## T11 - Electric Tracing In Lieu of Steam/Hot Glycol Tracing

### APPLICATION DESCRIPTION

*Heat tracing is used extensively in the oil and gas industry. Hot tracer fluid (usually steam or glycol) or electrical current is flowed adjacent to a line containing a substance which may solidify. The tracer fluid, which is continuously recirculated through a heater, or the electrical current transfers heat to the pipeline, thus preventing solid formation.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*T11a Electrical Summary*

*T11b Steam/Glycol Summary*

- *Thermostatically controllable only when required.*

### SUMMARY

**Industry Wide Facilities Characteristics**

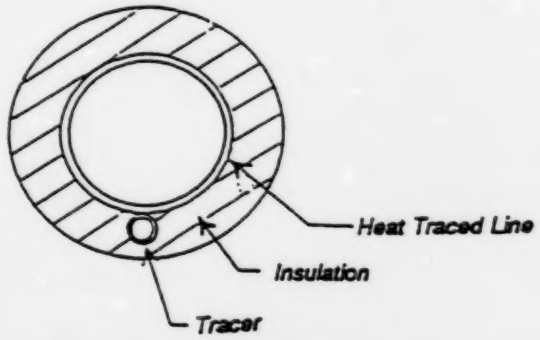
| | | |
|---|---|---|
| **Total Energy Consumption:** | *N/A* | (PJ/yr) : GWh |
| **Total # of Units:** | *550* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *0.00* | % |
| **Efficiency Improvement:** | *N/A* | % |
| **Energy Conserved:** | *0.00* | (PJ/yr) : GWh |
| **Differential Capital Cost** | *0.00* | $ |
| **Gross Economic Savings:** | *0.00* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *0.00* | $/kt/yr |
| **CO2 Conserved:** | *0.00* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *N.P.* | yrs |

### DIAGRAM/FIGURE




### NOTES

- *All informatin presented in summary is based on the total number of units in western Canada.*
- *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## T-11 Electric Tracing in Lieu of Steam/Hot Glycol Tracing

| OPPORTUNITY T11a: Electrical Summary | | | OPPORTUNITY T11c: Steam/Glycol Summary | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | 90.00 | % |
| Implementation: | 0.00 | % | Implementation: | 0.00 | % |
| Efficiency Improvement: | N/A | % | Efficiency Improvement: | N/A | % |
| Energy Conserved: | 0.00 | PJ/yr : (GWh) | Energy Conserved: | 0.00 | (PJ/yr) : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | 0.00 | $ |
| Gross Economic Savings: | 0.00 | $/yr | Gross Economic Savings: | 0.00 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr | CO2 Conserved: | 0.00 | kt/yr |
| Before Tax & Royalty Pay Back: | N/A | yrs | Before Tax & Royalty Pay Back: | N/A | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E1 - Compressors

### APPLICATION DESCRIPTION

*Positive displacement-type machinery includes rotary compressors, blowers, and vacuum pumps. These types of equipment operate at constant volume with variable discharge pressure. By implementing one of the four options below, significant energy savings may be obtained.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

- *E1a Energy Efficient Motors - Compare cost of installation of energy efficient motors to power savings.*
- *E1b Variable Speed Drives - Use drive speed adjustment to vary flowrate through compressor. Compare install/maintenance cost of electronic speed control to power consumption savings.*
- *E1c Auto Unloaders - use auto unloaders to reduce compression horsepower during low demand.*

### SUMMARY

**Industry Wide Facilities Characteristics**

| | | |
|---|---|---|
| **Total Energy Consumption:** | *2497.00* | PJ/yr : (GWh) |
| **Total # of Units:** | *454* | |

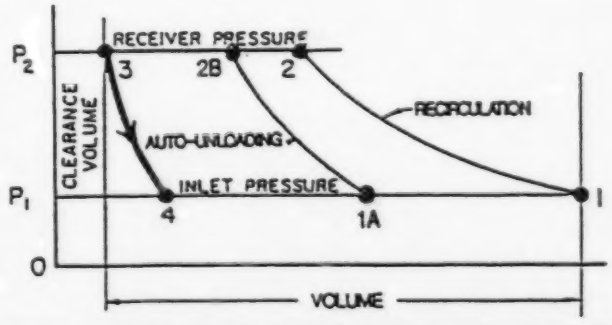
**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *64.00* | % |
| **Efficiency Improvement:** | *16.00* | % |
| **Energy Conserved:** | *255.69* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *1.89 x 10^6* | $ |
| **Gross Economic Savings:** | *9.05 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *8394* | $/kt/yr |
| **CO2 Conserved:** | *225.01* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0..21* | yrs |

### DIAGRAM/FIGURE

AUTO-UNLOADERS




### NOTES

** All informatin presented in summary is based on the total number of units in western Canada.*

** For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## E1 - Compressors

| OPPORTUNITY E1a: Energy Efficient Motors | | | OPPORTUNITY E1b: Variable Speed Drives | | |
|---|---|---|---|---|---|
| Application: | 80.00 | % | Application: | 80.00 | % |
| Implementation: | 80.00 | % | Implementation: | 80.00 | % |
| Efficiency Improvement: | 1.00 | % | Efficiency Improvement: | 15.00 | % |
| Energy Conserved: | 15.96 | PJ/yr : (GWh) | Energy Conserved: | 239.71 | PJ/yr : (GWh) |
| Differential Capital Cost: | 0.15 x 10^6 | $ | Differential Capital Cost: | 1.74 x 10^6 | $ |
| Gross Economic Savings: | 0.57 x 10^6 | $/yr | Gross Economic Savings: | 8.49 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 10331 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 8264 | $/kt/yr |
| CO2 Conserved: | 14.06 | kt/yr | CO2 Conserved: | 210.95 | kt/yr |
| Before Tax & Royalty Pay Back: | 0.26 | yrs | Before Tax & Royalty Pay Back: | 0.21 | yrs |

| OPPORTUNITY E1c: Auto Unloaders | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 80.00 | % | Application: | | % |
| Implementation: | 80.00 | % | Implementation: | | % |
| Efficiency Improvement: | 10.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 159.81 | PJ/yr : (GWh) | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 0.58 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 3.08 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 3918 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 148.30 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 0.19 | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E2 - Pump Systems

**APPLICATION DESCRIPTION**

*Pump systems are generally electrically driven in processing facilities. Typically single speed, low efficiency motors are used with bypass to control pressure and/or flow rates.*

**ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES**

**Opportunity**

*E2a Energy Efficient Motors - Compare cost of installation of energy efficient motors to power savings.*

*E2b Variable Speed Drives - Use drive speed adjustment to vary flowrate through pump. Compare install/maintenance cost of electronic speed control to power consumption savings.*

**SUMMARY**

**Industry Wide Facilities Characteristics**

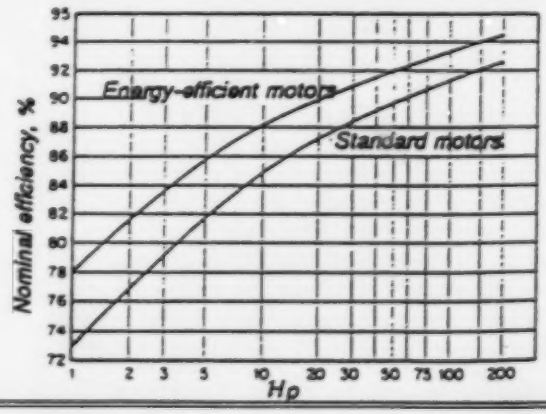
| | | |
|---|---|---|
| **Total Energy Consumption:** | *2349.00* | PJ/yr : (GWh) |
| **Total # of Units:** | *5042* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *80.00* | % |
| **Efficiency Improvement:** | *17.58* | % |
| **Energy Conserved:** | *330.36* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *13.31x10^6* | $ |
| **Gross Economic Savings:** | *11.69 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *45786* | $/kt/yr |
| **CO2 Conserved:** | *290.72* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *1.20* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## E2 - Pump Systems

| OPPORTUNITY E2a: Energy Efficient Motors | | | OPPORTUNITY E2b: Variable Speed Drives | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | 100.00 | % |
| Implementation: | 80.00 | % | Implementation: | 80.00 | % |
| Efficiency Improvement: | 2.58 | % | Efficiency Improvement: | 15.00 | % |
| Energy Conserved: | 48.48 | PJ/yr : (GWh) | Energy Conserved: | 281.88 | PJ/yr : (GWh) |
| Differential Capital Cost: | 1.21 x 10^6 | $ | Differential Capital Cost: | 12.1 x 10^6 | $ |
| Gross Economic Savings: | 1.72 x 10^6 | $/yr | Gross Economic Savings: | 9.98 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 28362 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 48783 | $/kt/yr |
| CO2 Conserved: | 42.67 | kt/yr | CO2 Conserved: | 248.05 | kt/yr |
| Before Tax & Royalty Pay Back: | 0.73 | yrs | Before Tax & Royalty Pay Back: | 1.29 | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E3 - Aerial Coolers

### APPLICATION DESCRIPTION

*Aerial coolers are required in processing facilities where heat must be removed during a refrigeration cycle (condensation) or for general process cooling. Fans for these coolers are generally operated at a constant speed with a constant pitch. The cooling capacity is typically varied by opening/closing louvers around the skirt of the cooler and by stopping or starting one of more of the fans.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*E3a Energy Efficient Motors: Cost comparison between installations of newer energy efficient motors vs cost of energy for old motors.*

*E3b Electronic Variable Speed Drives: Vary fan speed to match cooling demand. Cost comparison between capital install and maintenance of speed control and energy consumption savings.*

### SUMMARY

**Industry Wide Facilities Characteristics**

| | | |
|---|---|---|
| **Total Energy Consumption:** | *212.98* | PJ/yr : (GWh) |
| **Total # of Units:** | *3240* | |

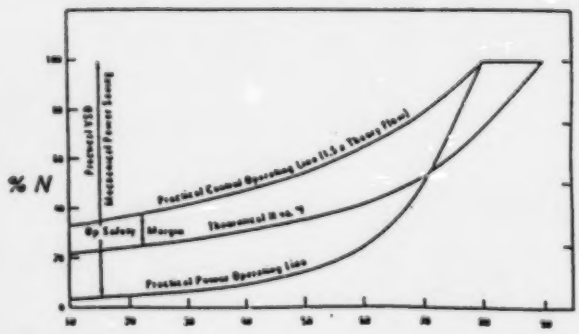
**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

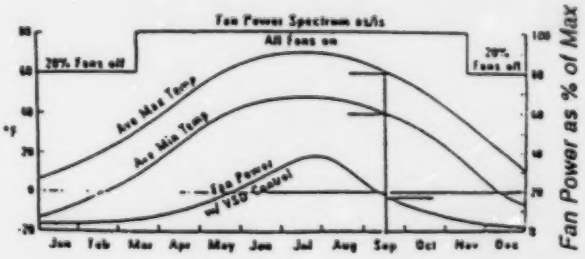
| | | |
|---|---|---|
| **Overall Penetration:** | *60.00* | % |
| **Efficiency Improvement:** | *69.65* | % |
| **Energy Conserved:** | *89.00* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *4.47 x 10^6* | $ |
| **Gross Economic Savings:** | *3.15 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *57087* | $/kt/yr |
| **CO2 Conserved:** | *78.32* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *1.52* | yrs |

### DIAGRAM/FIGURE

*Fan Operation - Potential Power Savings vs. Ambient Temp.*




*Fan Control & Power Consumption - Annual Cycle Savings Using VSD is Red Line Minus Green Line EG. In September with Day/Night Ambient Between 60° & 40°F, Saving is 82% of Power*




### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET
## Industrial Opportunity Summary
## E3 - Aerial Coolers

| OPPORTUNITY E3a: Energy Efficient Motors | | | OPPORTUNITY E3b: Electronics Var. Speed Drives | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | 100.00 | % |
| Implementation: | 60.00 | % | Implementation: | 60.00 | % |
| Efficiency Improvement: | 4.65 | % | Efficiency Improvement: | 65.00 | % |
| Energy Conserved: | 5.94 | PJ/yr : (GWh) | Energy Conserved: | 83.06 | PJ/yr : (GWh) |
| Differential Capital Cost: | 0.58 x 10^6 | $ | Differential Capital Cost: | 3.89 x 10^6 | $ |
| Gross Economic Savings: | 0.21 x 10^6 | $/yr | Gross Economic Savings: | 2.94 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 111533 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 53192 | $/kt/yr |
| CO2 Conserved: | 5.23 | kt/yr | CO2 Conserved: | 73.09 | kt/yr |
| Before Tax & Royalty Pay Back: | 3.20 | yrs | Before Tax & Royalty Pay Back: | 1.41 | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E4 - Lighting Improvements (per plant)

**APPLICATION DESCRIPTION**

*Lighting is used extensively in process facilities such as refineries and gas, petrochemical, straddle and fractionation plants. Exterior lighting levels in plants may be reduced by implementing photo-electric controls, timed controls or manual swithcing.*

**ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES**

**Opportunity**

- *E4a Reduce exterior lighting levels in large plants*
- *E4b Reduce exterior lighting levels in medium-sized plants*
- *E4c Reduce exterior lighting levels in small plants*
  *medium-sized plants*

**SUMMARY**

**Industry Wide Facilities Characteristics**

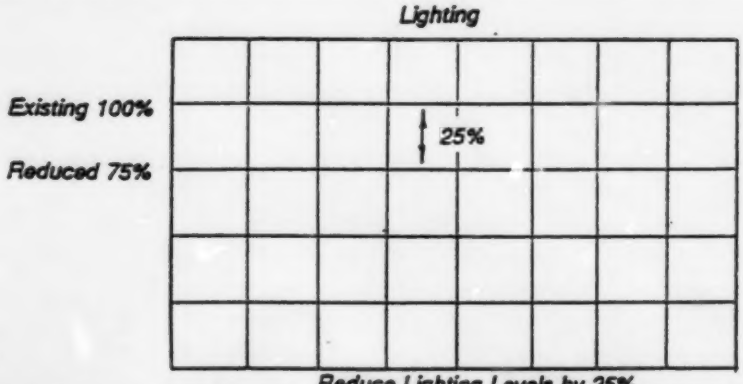
| | | |
|---|---|---|
| **Total Energy Consumption:** | *100.22* | PJ/yr : (GWh) |
| **Total # of Units:** | *550* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *20.00* | % |
| **Efficiency Improvement:** | *25.00* | % |
| **Energy Conserved:** | *5.01* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *0.69 x 10^6* | $ |
| **Gross Economic Savings:** | *0.18 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *156031* | $/kt/yr |
| **CO2 Conserved:** | *4.41* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *4.79* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## E4 - Lighting Improvements (per plant)

| OPPORTUNITY E4a: Reduce Light in Large Plants | | | OPPORTUNITY E4b: Reduce Light in Med. Plants | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | 100.00 | % |
| Implementation: | 20.00 | % | Implementation: | 20.00 | % |
| Efficiency Improvement: | 25.00 | % | Efficiency Improvement: | 25.00 | % |
| Energy Conserved: | 4.20 | PJ/yr : (GWh) | Energy Conserved: | 0.53 | PJ/yr : (GWh) |
| Differential Capital Cost: | 0.58 x 10^6 | $ | Differential Capital Cost: | 0.07 x 10^6 | $ |
| Gross Economic Savings: | 0.15 x 10^6 | $/yr | Gross Economic Savings: | 0.02 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 155666 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 160855 | $/kt/yr |
| CO2 Conserved: | 3.70 | kt/yr | CO2 Conserved: | 0.46 | kt/yr |
| Before Tax & Royalty Pay Back: | 4.77 | yrs | Before Tax & Royalty Pay Back: | 4.97 | yrs |

| OPPORTUNITY E4c: Reduce Light in Small Plants | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 100.00 | % | Application: | | % |
| Implementation: | 20.00 | % | Implementation: | | % |
| Efficiency Improvement: | 25.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 0.28 | PJ/yr : (GWh) | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 0.04 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 0.01 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 162199 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 0.25 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 5.03 | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E5 - Pump Jacks

**APPLICATION DESCRIPTION**

*Oil wells that do not flow naturally or at low rate require artificial lift. This is usually accomplished by means of a counterbalanced, mechanical pump (or pump jack) operating an electric or gas motor. Due to the variable demand on the motor through the pumping cycle, large peaks in the electric power demand are observed.*

**ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES**

**Opportunity**

*E5a* *Power Factor Connection - The counterbalanced pump produces large fluctuations in the motor's power draw. Power factor correction involves the installation of of capacitors that act as a buffer to damper out power requirement peaks. Compare the cost of implementing power factor corrections to savings resulting from decreased peak demands.*

**SUMMARY**

**Industry Wide Facilities Characteristics**

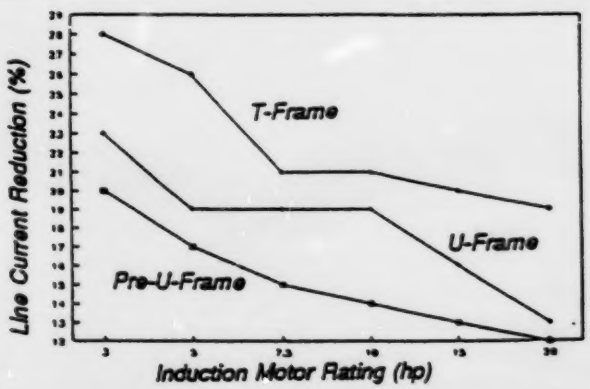
| | | |
|---|---|---|
| **Total Energy Consumption:** | *2726.00* | PJ/yr : (GWh) |
| **Total # of Units:** | *29016* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *18.00* | % |
| **Efficiency Improvement:** | *20.00* | % |
| **Energy Conserved:** | *98.14* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *1.31 x 10^6* | $ |
| **Gross Economic Savings:** | *3.47 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *15120* | $/kt/yr |
| **CO2 Conserved:** | *86.36* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *0.38* | yrs |

**DIAGRAM/FIGURE**




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET
## Industrial Opportunity Summary
## E5 - Pump Jacks

| OPPORTUNITY E5a: Power Factor Correction | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 90.00 | % | Application: | | % |
| Implementation: | 20.00 | % | Implementation: | | % |
| Efficiency Improvement: | 20.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 98.14 | PJ/yr : (GWh) | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 1.31 x 10^6 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 3.47 x 10^6 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 15120 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 86.36 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | 0.38 | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E6 - Lighting Improvements (per fixture)

### APPLICATION DESCRIPTION

*Lighting is used extensively in process facilities such as refineries and gas, petrochemical, straddle and fractionation plants. Replacing incandescent and mercury vapor lamps with high pressure sodium lamps utilizes less energy to provide more luminescence.*

### ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES

**Opportunity**

*E6a Replace incandescent with an HPS lamp.*

*E6b Replace mercury vapor with an HPS lamp.*

### SUMMARY

**Industry Wide Facilities Characteristics**

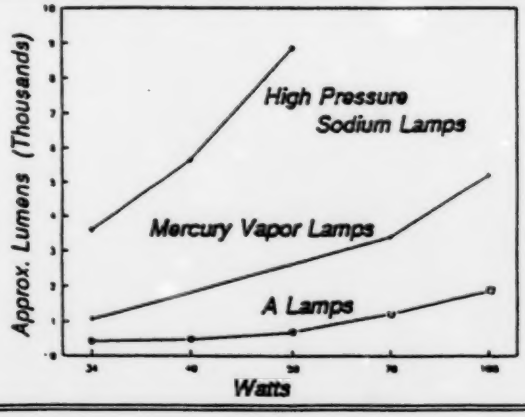
| | | |
|---|---|---|
| **Total Energy Consumption:** | *143.50* | PJ/yr : (GWh) |
| **Total # of Units:** | *42500* | |

**Energy/CO2 Conservation Opportunity Measures Economics**

***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***

| | | |
|---|---|---|
| **Overall Penetration:** | *28.53* | % |
| **Efficiency Improvement:** | *42.38* | % |
| **Energy Conserved:** | *17.35* | PJ/yr : (GWh) |
| **Differential Capital Cost** | *10.90 x 10^6* | $ |
| **Gross Economic Savings:** | *0.61 x 10^6* | $/yr |
| **Differential Operating Cost:** | *0.00* | $/yr |
| **Cap. Cost/kt CO2 Reduct./yr:** | *785347* | $/kt/yr |
| **CO2 Conserved:** | *15.27* | kt/yr |
| **Before Tax & Royalty Pay Back:** | *N.P.* | yrs |

### DIAGRAM/FIGURE




### NOTES

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## E6 - Lighting Improvements (per fixture)

| OPPORTUNITY E6a: Replace Incandescent w/ HPS | | | OPPORTUNITY E6b: Replace Mercury Vap. w/ HPS | | |
|---|---|---|---|---|---|
| Application: | 50.00 | % | Application: | 50.00 | % |
| Implementation: | 80.00 | % | Implementation: | 20.00 | % |
| Efficiency Improvement: | 50.00 | % | Efficiency Improvement: | 34.00 | % |
| Energy Conserved: | 15.02 | PJ/yr : (GWh) | Energy Conserved: | 2.32 | PJ/yr : (GWh) |
| Differential Capital Cost: | 8.92 x 10^6 | $ | Differential Capital Cost: | 1.97 x 10^6 | $ |
| Gross Economic Savings: | 0.53 x 10^6 | $/yr | Gross Economic Savings: | 0.08 x 10^6 | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | 0.00 | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 675009 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | 963597 | $/kt/yr |
| CO2 Conserved: | 13.22 | kt/yr | CO2 Conserved: | 2.05 | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | N.P. | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# DATA SHEET
## Overall Summary
## E7 - Pressure Reduction Energy Use

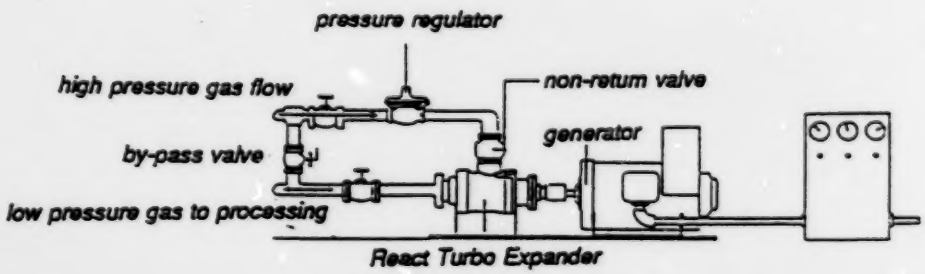
**APPLICATION DESCRIPTION**

*Transmission pipelines generally operate at relatively high pressures to allow high volume throughputs at low velocity and low pressure loss gradients. However, the pressure must be reduced at the point of use for burner fuel, etc. The pressure drop is usually accomplished through a pressure control valve or regulator, resulting in loss of energy to atmosphere.*

| ENERGY/CO2 CONSERVATION OPPORTUNITY MEASURES | SUMMARY |
|---|---|
| **Opportunity** | **Industry Wide Facilities Characteristics** |
| *E7a Reaction Turbines - The pressure drop required at the regulating station can be accomplished by expanding the gas stream through a turbine. The turbine can be coupled to an electric generator which feeds power to the electrical grid. Compare capital cost of installation and maintenance of raction turbine/generator sets with revenue from selling electric power back into the grid* | **Total Energy Consumption:** 819.00 PJ/yr : (GWh)<br>**Total # of Units:** 557<br><br>**Energy/CO2 Conservation Opportunity Measures Economics**<br>***(All values are based on the implementation of all opportunity measures using the concept of diminishing returns.)***<br><br>**Overall Penetration:** 0.00 %<br>**Efficiency Improvement:** 15.00 %<br>**Energy Conserved:** 0.00 PJ/yr : (GWh)<br>**Differential Capital Cost** 0.00 $<br>**Gross Economic Savings:** 0.00 $/yr<br>**Differential Operating Cost:** 0.00 $/yr<br>**Cap. Cost/kt CO2 Reduct./yr:** 0 $/kt/yr<br>**CO2 Conserved:** 0.00 kt/yr<br>**Before Tax & Royalty Pay Back:** N.P. yrs |

**DIAGRAM/FIGURE**

*Typical Let-Down Application*




**NOTES**

* *All informatin presented in summary is based on the total number of units in western Canada.*
* *For individual units information, see Table B4.1-1.*

# DATA SHEET

## Industrial Opportunity Summary

## E7 - Pressure Reduction Energy Use

| OPPORTUNITY E7a: Pressure Reduct. Energy Use | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | 50.00 | % | Application: | | % |
| Implementation: | 0.00 | % | Implementation: | | % |
| Efficiency Improvement: | 15.00 | % | Efficiency Improvement: | | % |
| Energy Conserved: | 0.00 | PJ/yr : (GWh) | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | 0.00 | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | 0.00 | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | 0.00 | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | 0 | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | 0.00 | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | N.P. | yrs | Before Tax & Royalty Pay Back: | | yrs |

| OPPORTUNITY | | | OPPORTUNITY | | |
|---|---|---|---|---|---|
| Application: | | % | Application: | | % |
| Implementation: | | % | Implementation: | | % |
| Efficiency Improvement: | | % | Efficiency Improvement: | | % |
| Energy Conserved: | | PJ/yr : GWh | Energy Conserved: | | PJ/yr : GWh |
| Differential Capital Cost: | | $ | Differential Capital Cost: | | $ |
| Gross Economic Savings: | | $/yr | Gross Economic Savings: | | $/yr |
| Differential Operating Cost: | | $/yr | Differential Operating Cost: | | $/yr |
| Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr | Cap. Cost/kt CO2 Reduct./yr | | $/kt/yr |
| CO2 Conserved: | | kt/yr | CO2 Conserved: | | kt/yr |
| Before Tax & Royalty Pay Back: | | yrs | Before Tax & Royalty Pay Back: | | yrs |

# APPENDIX C

## Supplementary List

# APPENDIX C

## SUPPLEMENTARY LIST

### C1.0 "JUST TO SPEC" PROCESS CONTROL

Aside from dehydration, this study has not explored the common approach of producing gas, NGL and crudes with qualities above specifications. Each lease and plant should examine its operations closely in this regard. Many refiners, for example, have product quality giveaway control committees - possibly oil and gas producers need similar approaches.

Inexpensive analyzers and new process microcomputer control technology would allow great improvement via feed forward and feedback approaches.

### C2.0 INDUSTRY ORGANIZATION

This study struggled with the problem of under utilized plants but left such consideration to individual operators for study. There may be significant energy savings but a case by case analysis is warranted. Certainly the need for energy input reduction should become a factor in considering downsizing or shutdown.

A number of cases were noted where there were several dehydrators in series as gas passed from one system to another. This too was left to the individual operator.

The potential for higher allowable water contents particularly in lower pressure gas systems was reviewed, but must be considered at the individual system level as there may be serious problems in some systems with any change. Possible increased B S & W allowances in crude oils is a similar subject.

## C3.0 THERMAL

The following are items not evaluated, but considered of very significant potential for savings:

### C3.1 OVER DESIGN/OVER COMPENSATION BY FIELD OPERATIONS

The following often used saying identifies an opportunity in process control: "If one work, then two is better and three must be better yet". This supports the philosophy of; "to be sure it's going to work, let's design or operate conservatively".

It has been identified that this philosophy frequently results in designing or field setting circulation rates substantially higher than what is required in solvent systems, distillation columns and glycol dehydration systems. Distillation towers can be particularly poor because the problem can be made greater and greater by turning up the heat from the reboiler and then balancing this with increased condensing energy and increased reflux.

Also, refrigeration systems for dewpoint control are often set to overcool just to be positive there won't be problems.

In addition, often excess purge gas is being used in flare systems.

All of these practices consume excess power above what is needed to do the job. More attention to the details should result in significant savings.

### C3.2 PLANT CONSOLIDATIONS

Generally speaking, plants that are run substantially off design are inefficient to varying degrees. There are many mature fields whose production volumes have substantially declined thereby resulting in a number of potentially inefficient plants which are operating well of the best efficiency design point.

Operators with plants in this situation should look to consolidating their operations with others nearby to improve efficiencies and also take advantage of the economy of scale for retrofitting with better equipment for better control.

## C3.3 RETROFIT FOR REDUCED THROUGHPUT

As noted above, plants that are running off design are inefficient to varying degrees. An indepth look should be taken to see if the plants could be retrofitted to better match the reduced throughput and bring the efficiency back into line. With increased efficiency, $CO_2$ levels will be reduced.

## C3.4 PROCESS HEATER EFFICIENCY UPGRADES

Process heaters at plant sites are generally better attended and adjusted than their field counterparts. However, many of the features discussed for upgrading field heaters in Appendix A, Item T8 of this report could still be beneficially applied to plant process heaters to substantially increase their efficiency.

Turbulators, better burners and preheat of combustion air are examples of such approaches.

## C3.5 COMPRESSOR SYSTEM OPTIMIZATION

It is standard practice to run the large gas transportation pipeline systems at full design pressure 6894 kPa (1000 psig) all year long, yet in certain months (summer) it is hypothesized that demand is less and line pack is not as necessary. If the main pipeline systems operating pressure could be reduced, it would reduce horsepower requirements for all producers delivering to them with a proportionate reduction in energy consumed. These energy savings could be dramatic.

## C3.6 ADVANCED HEAT EXCHANGE SELECTION

Pinch point and similar advanced formalized approaches to enhancing heat recovery at existing the hurdle rate were noted by many contacts. Such approaches are directly applicable for large installation design and more importantly, redesign. However, for smaller operations, a travelling specialist with some simple "how to do it" curves and approaches is probably essential. Many standard systems, e.g. dehydrators, can be examined or generic cases and standardized improvements developed.

## C3.7 OPTIMUM PIPELINE HEATING SYSTEMS

Heating pipelines with hot glycol tracing is being used in lieu of line heaters, dehydration, glycol injection or methanol injection. The glycol can be heated using waste heat from engines, heater exhausts or burning waste flare gas.

# C4.0 ELECTRICAL SUPPLEMENTARY LIST

The following were considered the most likely improvements beyond the short list, but each operator will have his own special cases.

## C4.1 POWER FACTOR CORRECTIONS

The addition of power factor correction capacitors is normal practice for most oil and gas companies. The exception would be the "unaware" who are not cognizant of their utility costs. The amount of power factor correction installed is directly related to power factor penalty imposed by the utility companies.

## C4.2 UPGRADE OBSOLETE CONTROL SYSTEMS

The electronic and computer based control system have now been established throughout the oil and gas industry. The higher degree of accuracy has been

(Hydrocarbon Processing, November 1989, pages 63 to 67) demonstrated repeatedly. Some of the benefits are:

- Less off spec product
- Six times faster recovery from process upsets
- Improved steady state times
- Reduced transition times between products

A direct correlation with energy conservation is unlikely and probably irrelevant. Due to technology and competition, control systems upgrading will probably continue to occur, resulting in some degree of energy conservation.

## C4.3 DISTRIBUTION SYSTEM IMPROVEMENTS

As the design stage, many projects are designed without consideration for energy conservation. Usually what works before is repeated as acceptable design standards. Cable or bus sizing, high efficiency transformers, efficient equipment layouts all could provide some improvement in energy conservation.

Also, in-plant cables are often sized just large enough to meet code. It was suggested that although code size cables may be adequate from a safety standpoint, larger cables could offer up to 3 percent reduction in in-plant line losses.

As society becomes more "energy conservation" conscious, many small improvements will occur in design, operations and maintenance that are undefinable.

## C4.4 ELECTRICITY PEAKING

Load shedding control to reduce peaks is a tool used by managers of energy systems today. Peak shaving does not limit energy consumption but does allow

the electric utility to reduce their "spinning reserve" on the system - thus conserving energy.

Peak shaving generation on the other hand is done for economic reasons - creating a possibility of many small (less efficient) generating units.

## C5.0 ENERGY CONSCIOUSNESS/COMMITTEES

Lease and plant energy committees, along the lines of the present safety committees, are strongly recommended. With coming needs for energy and environmental audits, such committees appear as musts. RTM's experience with corporate energy consciousness and such committees indicates an initial minimum saving of one percent of energy inputs in the oil and gas industries. Ongoing improvements should be in the 0.2 percent or higher range. Such savings are above and beyond the items identified in the short list of this study and also often beyond the other items of this supplemental list.